ProEx Energy Ltd. Annual Report

05

ProEx Energy Ltd. Trades on the Toronto Stock Exchange under the symbol PXE. ProEx Energy Ltd. is a natural gas and crude oil exploration and production company headquartered in Calgary, Alberta, Canada with operations focused in northeastern British Columbia.

ProEx Energy Ltd.

PXE

ADVISORY - Certain information regarding ProEx Energy Ltd. set forth in this document, including management's assessment of ProEx Energy Ltd.'s future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond ProEx Energy Ltd.'s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. ProEx Energy Ltd.'s actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that ProEx Energy Ltd. will derive therefrom.

Q4 2005 Average Production
4,561
BOE/D

Average 2005 Production
3,162
BOE/D

PROEX ENERGY LTD. (PROEX) IS A PURE, HIGH GROWTH NORTHEAST BRITISH COLUMBIA EXPLORATION COMPANY WITH AN EXCEPTIONAL LAND POSITION IN AN EMERGING REGIONAL NATURAL GAS PLAY. THE COMPANY HAS A HIGH WORKING INTEREST, CONTROL AND OPERATORSHIP OF THE PLAY. IT IS A REPEATABLE TIGHT GAS PLAY CONCEPT IN WHICH PROEX HAS DEVELOPED LEADING TECHNICAL COMPETENCIES. THE AREA ALSO FEATURES YEAR ROUND ACCESS WITH ITS CLOSE PROXIMITY TO THE ALASKA HIGHWAY AND PROEX CONTROLS LOCAL INFRASTRUCTURE. THE COMPANY HAS SECURED GATHERING AND PROCESSING WITHIN THE PROVINCIAL SYSTEM TO HANDLE FUTURE GROWTH. THE COMPANY HAS ACHIEVED PRODUCTION AND RESERVE GROWTH WITH LOW ON-STREAM AND FINDING AND DEVELOPMENT COSTS.

The Company's production growth during 2005 was generated through the drill bit. The Company invested approximately $85.5 million during 2005 in its exploration and development program

2005

Financial and Operating Highlights

($ thousands except per share amounts)	**2005**	2004(1)
Production		
- Natural gas (mcf/d)	**16,864**	5,092
- Crude oil (bbls/d)	**274**	263
- NGL (bbls/d)	**77**	49
- BOE (boe/d)	**3,162**	1,161
Reserves (proved plus probable)		
- Natural gas (mmcf)	**82,141**	35,366
- Light and Medium Oil (mbbls)	**651**	655
- Natural Gas Liquids (mbbls)	**683**	278
- Total (mboe)	**15,024**	6,827
Total oil and gas revenues ($ thousands)	**68,086**	9,515
Cash flow from operations	**36,044**	4,755
- Basic per share	**1.17**	0.18
- Diluted per share	**0.96**	0.14
Net earnings	**15,015**	1,717
- Basic per share	**0.49**	0.06
- Diluted per share	**0.40**	0.05
Capital Investment	**85,454**	36,366
Total assets	**150,193**	72,774
Bank debt and working capital deficiency	**9,275**	11,681

(1) Period ended from July 2, 2004 to December 31, 2004

2005 Capital Investment
$85.5 million

2005 Cash Flow from Operations
$36.0 million

2005 PRESIDENT'S MESSAGE

2005 was a great year for ProEx. The Company invested approximately $85.5 million during the year and generated significant production and reserve growth.

Production increased to 4,561 boe per day in the fourth quarter from 1,370 boe per day in the fourth quarter of 2004, an increase of 233 percent and 190 percent on a per diluted share basis.

Proved plus probable reserves increased to 15 million boe from 6.8 million boe at December 31, 2004, for an increase of 120 percent and an increase of 95 percent per diluted share.

The Company significantly increased its undeveloped land position in northeast British Columbia adding approximately 50,000 net acres through Crown land sales, property acquisition and industry farm-ins. Total undeveloped land under control at year end was 207,000 acres.

The Company shot over 200 square kilometers of 3-D seismic data to bring the total area evaluated by Company owned 3-D seismic to 585 square kilometers at year end.

During the first quarter, the Company positioned itself as a pure British Columbia exploration and development play with the disposition of all of its Alberta assets. The Company is now concentrated solely in northeast British Columbia.

ProEx's growth efforts are focused in the Foothills where it has built an exceptional land position in an emerging regional tight gas play. The Company has high working interests, control and operatorship of the play. This repeatable play concept has been developed over the past several years utilizing leading technical competencies. The operating area features year round access with close proximity to the Alaska Highway. ProEx controls local facility and road infrastructure and has secured gathering and processing capacity within the provincial system to handle future growth. The Company has generated strong production and reserve growth while on-stream costs and finding and development costs continue to be among the most efficient in the industry.

The Company's 2005 capital investment program generated reserve additions at a cost of $9.85 per boe on a proved plus probable basis and production additions with an on stream cost of $16,805 per boe per day.

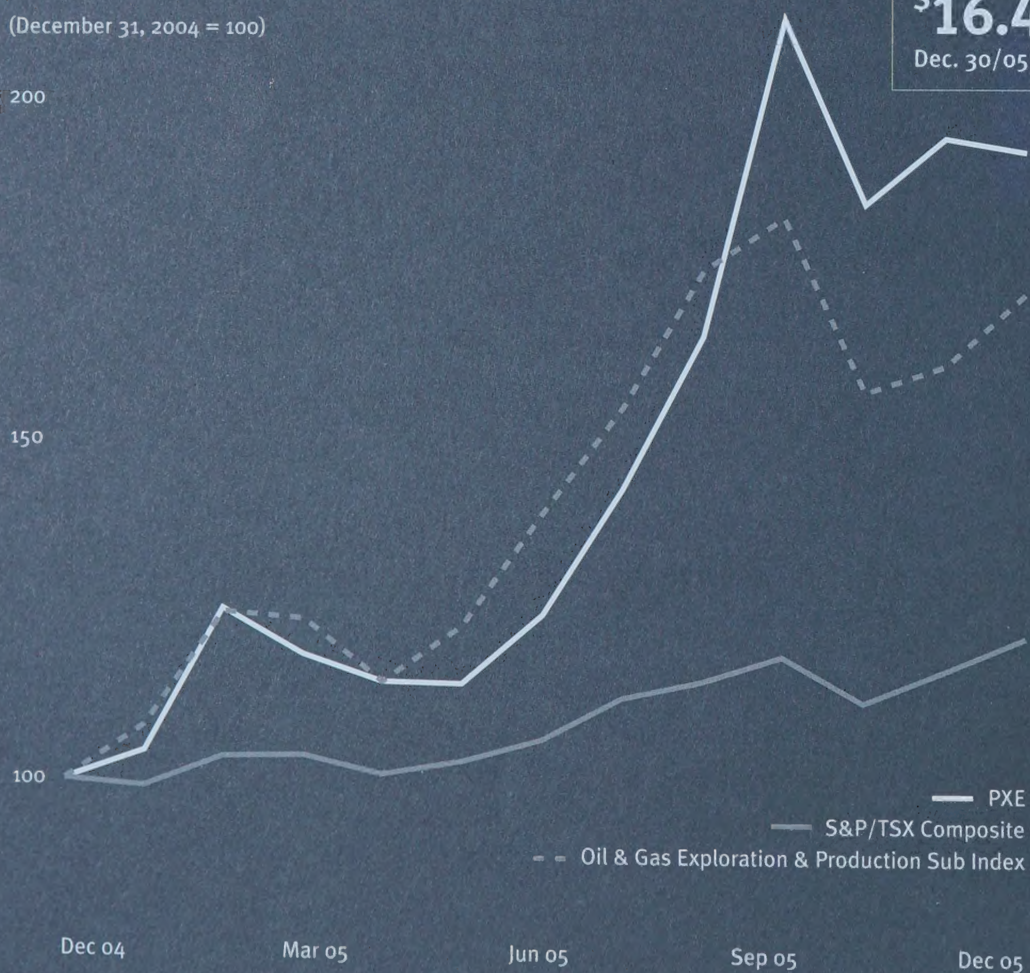
2005

Share Price Performance

PXE Share Price

$16.40

Dec. 30/05



2005 Finding Development & Acquisition Costs

$9.85

per boe proved and probable

2005 Production Additional Costs

$16,805

per boe per day

For 2005, capital efficiencies were in line with the prior year as well as the Company's expectancy for future full cycle metrics. Production addition costs where $16,805 per boe per day while all in finding, development and acquisition costs inclusive of changes in future capital were $9.85 per boe on a proved plus probable basis.

ProEx financed its 2005 program with the proceeds of two equity offerings during the year, cash flow and bank debt. The Company issued 2,500,000 common shares in February at a price of $9.10 per share and issued 2,500,000 common shares in August at a price of $12.40 per share.

Cash flow from operations for the year was $36.0 million compared to $4.8 million in 2004 and net earnings were $15.0 million for 2005 compared to $1.7 million during 2004. The Company ended 2005 with net debt of $9.2 million on a borrowing base of $45 million.

ProEx drilled a total of 28.6 net wells resulting in 26.2 net gas wells and 0.8 net oil wells for an overall success rate of 94 percent. Foothills drilling represented the vast majority of the year's activity with 23.5 successful natural gas wells.

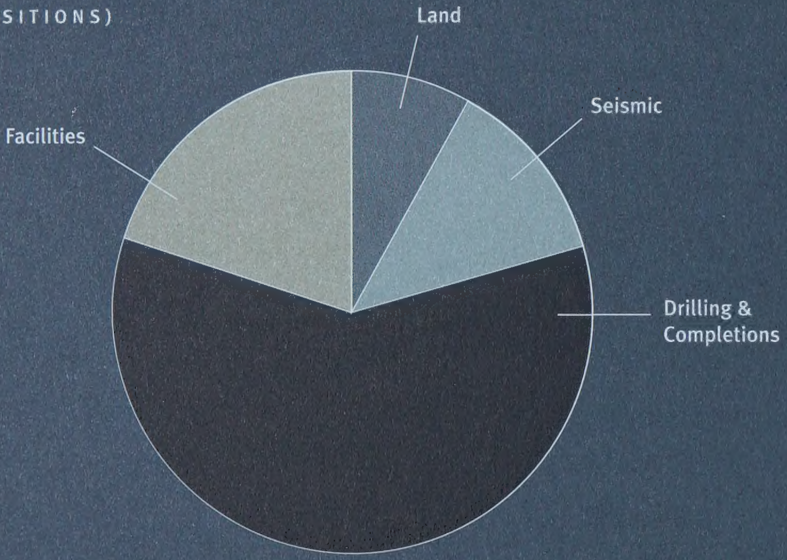
During the year the Company expanded its Foothills program with extension drilling at Gundy, Town and Altares as well as conducting a successful exploration program at West Beg. Production ramped up during the year with the most significant increase occurring late in the third quarter with the construction of the West Beg compression facility. This resulted in ProEx achieving its exit production targets ahead of schedule. This success in turn allowed the Company to focus its efforts for the winter program on testing several new features identified by the 3-D seismic data acquired during 2005.

ProEx is an active driller and land acquirer in northeastern British Columbia. During 2005, the Company drilled 45 gross wells (28.6 net) and added approximately 37,000 acres of undeveloped land.

2005

Capital Investment

2005 CAPITAL SPENDING (BEFORE DISPOSITIONS)



2005 DRILLING RESULTS

Average Proved Plus Probable Reserves per Well Drilled in 2005

2.0 bcfe

28.6 Net Wells Drilled

94% Success

For 2006 ProEx will invest approximately $85 million in exploration and development activities and is planning to drill between 30 to 40 net wells, primarily in the Foothills foldbelt in northeast British Columbia. The Company estimates that approximately 50 percent of the capital program will be invested in the first quarter. ProEx will continue to concentrate on its traditional Foothills targeted Halfway reservoirs and in addition, will drill at least one of several deeper Mississippian-aged Debolt tests in the Foothills as well developing a shallow Cretaceous program for later in the year.

Annual production is expected to average between 6,300 to 6,700 barrels of oil equivalent (boe) per day in 2006 with an exit range of 7,000 to 7,500 boe per day. Due to the timing of drilling and facility construction during the first quarter of 2006, the bulk of production gains are anticipated to come in the later part of the first quarter and into the second quarter.

In the first quarter of 2006, ProEx is shooting a 280 square kilometer 3-D program at Sasquatch, adjacent and on trend to the existing ProEx 3-D data in the Foothills, which now totals 865 square kilometres. This data will be processed and interpreted during the second quarter and provide a detailed subsurface picture of the reservoir structure. The Company expects that this will extend its drilling inventory for 2007 and beyond.

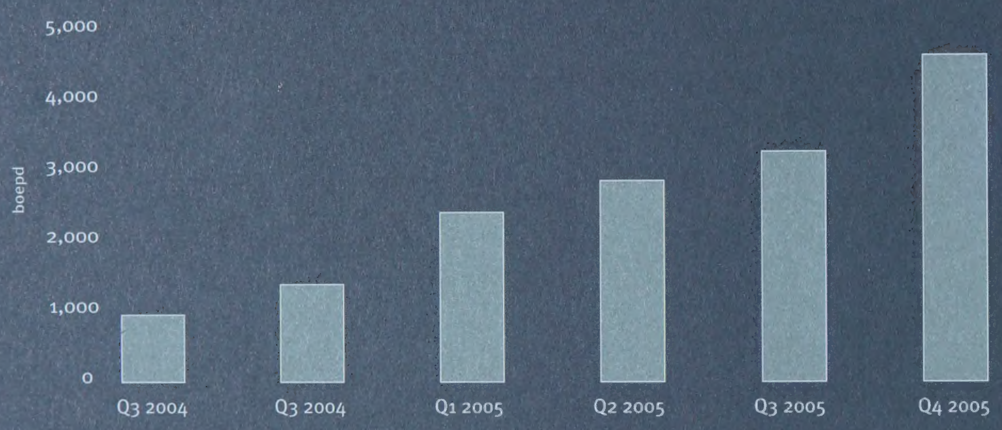
The Fort St. John Plains region will continue to be a core holding. ProEx participates with its partner, Progress Energy Trust, in their development program with the objective of maintaining production in the range of 1,200 to 1,500 boe per day. The region remains a high netback area and generates cash flow which is re-invested in long life Foothills opportunities.

ProEx is budgeting the investment of $85 million during 2006 and is planning to drill between 50 and 60 gross wells. The program is expected to deliver average production between 6,300 and 6,700 boe per day in 2006.

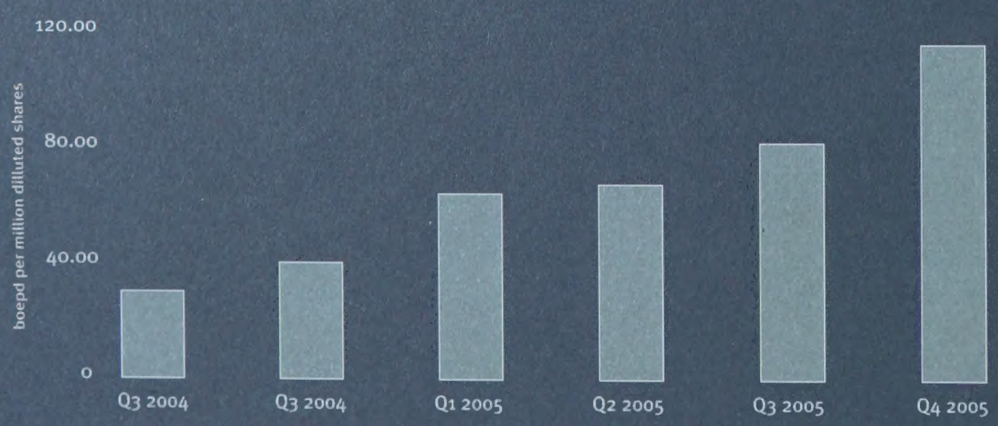
2005

Quarterly Production

QUARTERLY PRODUCTION GROWTH



PRODUCTION GROWTH PER SHARE



2005 Production per Share Growth **142** percent

2005 Proved Reserves growth per share, Diluted **105** percent

Strong natural gas prices and buoyant capital markets have increased the competitive landscape in the Western Canadian Sedimentary Basin evidenced by the increased competition for lands and assets in the Foothills of northeast British Columbia. ProEx is well positioned with a large undeveloped land position and the technical knowledge to execute its strategy. ProEx continues to build its undeveloped land position and hence the opportunity base in the British Columbia Foothills through a combination of asset purchases, Crown purchases and farm-ins where contracted drilling rigs are used to earn land. This farm-in strategy allows the Company to test concepts and apply technical competencies while capturing new lands at a faster pace and at lower prices as compared to just simply participating in Crown land sales. A large undeveloped land base provides significant depth of inventory that provides shareholders with upside for 2006 and 2007.

ProEx will continue to focus on traditional efficiency measures targeting finding, development and net acquisition costs in the $10 to $12 per boe range on a proved plus probable basis and production on-stream costs under $20,000 per boe per day. ProEx has been able to achieve these levels of efficiencies due the quality of the assets combined with the knowledge, skill and creativity of its staff. As all staff are owners of ProEx, the Company is focused on the creation of value through the exploration and development cycle and will continue to measure success in terms of per share value gain.

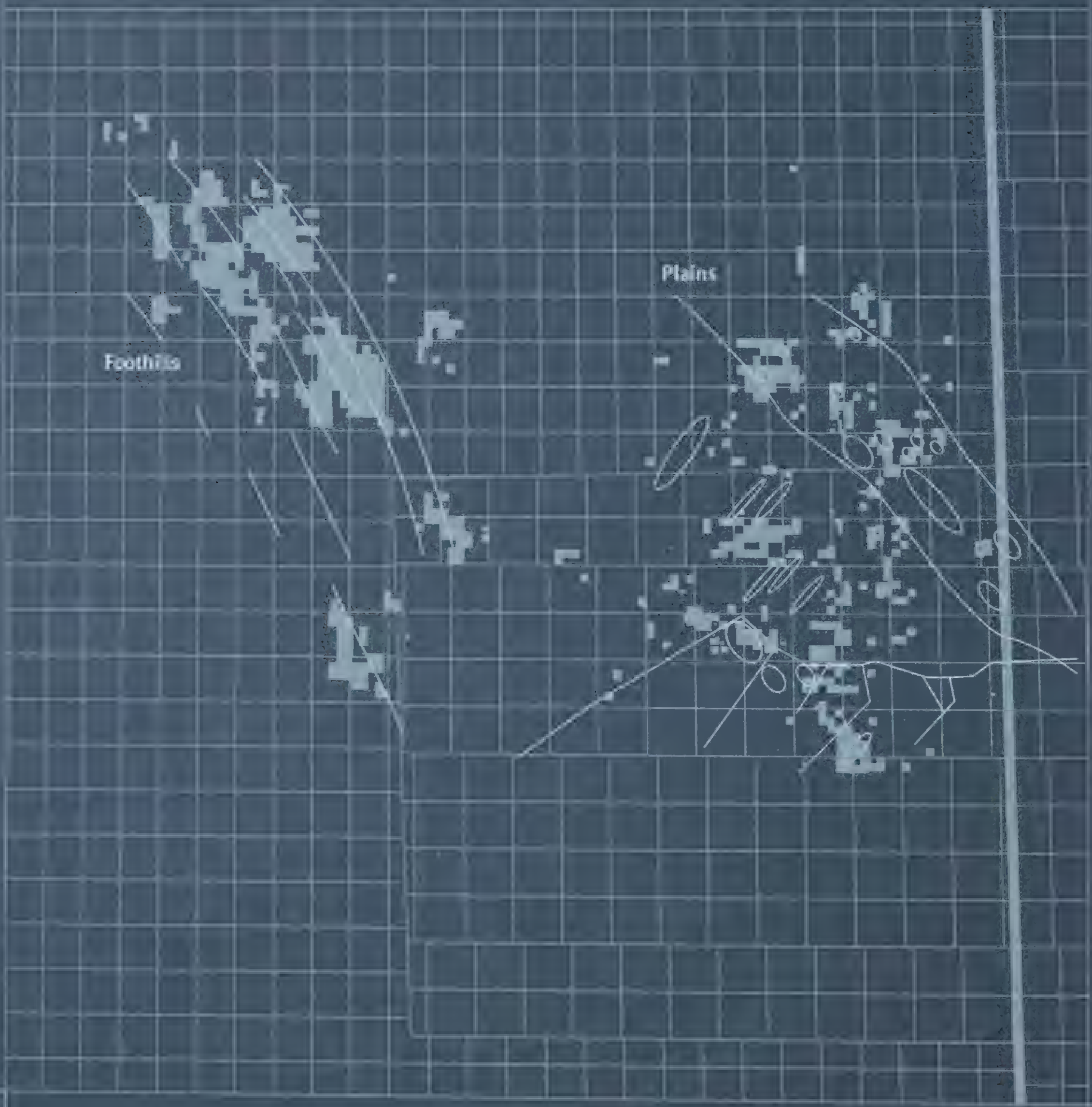
David D. Johnson,
President and Chief Executive Officer

February 28, 2006

ProEx is a pure northeast British Columbia exploration Company with a large undeveloped land base focused in the Foothills and Plains regions.

2005

Northeast British Columbia – Plains and Foothills



2005 Year End Total Proved and Probable Reserves **15,024** mboe

Natural Gas as Percent of Total Proved and Probable Reserves **91** percent

Northeast British Columbia

ProEx Energy Ltd. completed its transformation into a pure northeast British Columbia exploration and production company in 2005 with the sale of its Halkirk Alberta properties in the early part of the year. The company redeployed proceeds of this asset sale to further strengthen and concentrate ProEx's foothills natural gas lands and production. Through a combination of Crown land acquisitions and large regional farmins with adjacent mineral owners the company has more than doubled its acreage holdings in the Halfway gas fairways as defined by 3-D seismic surveys and in-house geological mapping. At December 31, 2005, the company has approximately 207,000 acres of land under control in northeast British Columbia.

In 2005 ProEx participated in 46 drills in northeast British Columbia, 30 (23.5 net) of which were located in the Foothills and 16 (6.1 net) in the Fort St. John plains area. Foothills drilling was directed to exploring for and producing natural gas from the Triassic aged Halfway reservoir. This 100 to 150 foot thick sandstone reservoir contains natural gas in commercial quantities where situated in subsurface anticlinal drape positions over underlying structures. Much of the mid-year 2005 drilling program was directed at extension drilling along the West Beg anticline resulting in a succession of successful new Halfway producing wells. Elsewhere, ProEx drilled successful wells at Altares and Gundy producing properties. In 2005 ProEx recorded over 200 square kilometers of 3-D seismic that is utilized to image these structures. Including 3-D seismic recorded in the first quarter of 2006, this database is now 865 square kilometers in size providing the company with a comprehensive view of the subsurface reservoirs under its control. This data will allow ProEx to direct future drill programs with precision along the crests of the Halfway anticlines.

The Company's British Columbia Foothills will be the focus and growth driver. The Company has a significant undeveloped land position and extensive 3D seismic coverage.

2005 | British Columbia Foothills

Foothills
Seismic
Coverage
865
square kilometers

Undeveloped
Acres
Under ProEx
Control
207,000
acres

In the Fort St John plains area, the largely shallow drilling program delivered a 74% commercial well success rate. In the north portion of this area ProEx successfully completed the drilling commitments on a farmin to a Canadian major exploration and production company while elsewhere with Progress Trust ProEx participated at an average 20% working interest in a modest drill program. ProEx shares a common business mandate with its partner Progress Energy in that drilling will be conducted to maintain production volumes. Cash generated from this light oil and gas region will be redeployed on advancing longer life natural gas projects in the Foothills of northeast British Columbia.

For 2006, ProEx will continue its aggressive expansion efforts into the Foothills of northeast British Columbia with a planned robust drilling, land and seismic acquisition program. The bulk of the first half drilling efforts will be conducted towards exploratory drilling on 10 untested features, each of which could lead to development programs of varying sizes for the balance of the year. In addition, in the first quarter of the year ProEx will be recording over 280 square kilometers of 3-D seismic across prospective lands acquired in the past 18 months. This program which is expected to be interpreted by the end of the second quarter of 2006 will provide additional exploration and development locations for 2006 and beyond. In the Fort St John area with Progress Energy Trust a 2-D seismic program will be conducted over company controlled lands. This program along with development plans in and around existing producing properties is expected to generate two to three net drills for 2006.

2006 Forecast Capital Investment

$85 Million

2005 Proved Plus Probable Recycle Ratio

3.3x

Management's Discussion and Analysis

M D & A

2005

ProEx Energy Ltd.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

ProEx Energy Ltd.

The following discussion and analysis as provided by the Management of ProEx Energy Ltd. ("ProEx" or "Company") as of February 28, 2006, is to be read in conjunction with the accompanying audited financial statements and related notes for the year ended December 31, 2005 and the period from July 2, 2004 to December 31, 2004. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Description of Company – ProEx Energy Ltd. is a Calgary based, natural gas focused, exploration and development company, established on July 2, 2004 under a Plan of Arrangement (refer to Creation of ProEx Energy Ltd.) The comparative financial results are for the period from July 2, 2004 to December 31, 2004.

Non-GAAP Measures – The MD&A contains the term "funds generated from operations" and "netbacks" which are non-GAAP terms. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds generated from operations to analyze operating performance and leverage and considers funds generated from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds generated from operations should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian GAAP as an indicator of the Company's performance. Therefore references to funds generated from operations or funds generated from operations per share (basic and diluted) may not be comparable with the calculation of similar measures for other entities. The reconciliation between net earnings, funds generated from operations and cash flow from operations can be found in the statements of cash flows in the year end audited financial statements. Funds generated from operations per share is calculated using the basic and diluted weighted average number of shares for the period.

Boe Presentation – Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet ("mcf") to one barrel ("bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six mcf of gas to one barrel of oil.

Forward-Looking Information – Certain information regarding the Company set forth in this document, including Management's assessment of the Company's future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

CREATION OF PROEX ENERGY LTD.

ProEx began its existence on July 2, 2004 through the closing of a Plan of Arrangement between Progress Energy Ltd. ("Progress"), Cequel Energy Inc. ("Cequel"), Progress Energy Trust, Cyries Energy Inc. and ProEx ("Plan of Arrangement"). Through the Plan of Arrangement, ProEx received interests in certain oil and natural gas properties

formerly owned by Progress including a 20 percent ownership of certain of Progress' interest in oil and natural gas properties in the Fort St. John Plains region of British Columbia, a 100 percent ownership in Progress' interest at Halkirk, Alberta and an 80 percent ownership in certain undeveloped lands in the Foothills region of British Columbia. At inception, these properties produced approximately 1,000 boe per day of natural gas and liquids.

2005 HIGHLIGHTS AND SELECTED FINANCIAL INFORMATION

($ thousands, except per share amounts)	**2005**	Period from July 2 to December 31, 2004
Production		
- Natural gas (mcf/d)	**16,864**	5,092
- Crude oil (bbls/d)	**274**	263
- Natural gas liquids (bbls/d)	**77**	49
- Total production (boe/d)	**3,162**	1,161
Pricing		
- Natural gas ($/mcf)	**9.70**	6.97
- Crude oil ($/bbl)	**66.49**	54.49
- Natural gas liquids ($/bbl)	**62.32**	44.59
Petroleum and natural gas revenue	**68,086**	9,519
Funds generated from operations	**36,044**	4,755
- Basic per share	**1.17**	0.18
- Diluted per share	**0.96**	0.14
Net earnings	**15,015**	1,717
- Basic per share	**0.49**	0.06
- Diluted per share	**0.40**	0.05
Capital expenditures	**85,454**	36,366
Total assets	**150,193**	72,774
Bank debt and working capital deficiency	**9,275**	11,681

OPERATIONS

- Average 2005 production was 3,162 boe per day compared to 1,161 boe per day during the period from July 2, 2004 to December 31, 2004 (the "prior year"), an increase of 172 percent while production per diluted share increased 142 percent during the same period.
- 2005 fourth quarter production averaged 4,561 boe per day compared to 1,370 boe per day in the fourth quarter of 2004, an increase of 233 percent while production per diluted share increased 195 percent during the same period.
- Natural gas production was 24,942 mcf per day during the fourth quarter of 2005 compared to 17,255 mcf per day during the prior quarter and 6,365 mcf per day in the fourth quarter of 2004.
- Crude oil and natural gas liquids production averaged 404 bbls per day during the fourth quarter of 2005 compared to 338 bbls per day in the prior quarter and 309 bbls per day in the fourth quarter of 2004.
- Drilled 45 gross wells (28.6 net) during the year with a 94 percent success rate, resulting in 37 natural gas wells (26.2 net) and 4 oil wells (0.8 net).

- During the year, the Company increased net undeveloped land to 160,869 net acres from 123,674 net acres at December 31, 2004. At December 31, 2005 undeveloped lands under the control of ProEx, including option acreage, is approximately 207,000 net acres.

RESERVES

- Proved reserves at December 31, 2005 were 11.8 million boe compared to 5.1 million boe at December 31, 2004, an increase of 131 percent while reserves per diluted share increased 105 percent during the same period.
- Proved plus probable reserves at December 31, 2005 were 15.0 million boe compared to 6.8 million boe at December 31, 2004, an increase of 120 percent while proved plus probable reserves per diluted share increased 95 percent during the same period.
- Production replacement on a proved reserve basis was 6.8 times and on a proved plus probable reserve basis was 8.1 times.
- The average proved plus probable reserve additions per well during 2005 was approximately 2.0 bcf of natural gas.

CAPITAL EFFICIENCY

- Finding, development and net acquisition costs ("FD&A") related to the total 2005 capital program (including the change in future development capital) were $11.97 per boe proved and $9.85 per boe proved plus probable. This translates into a recycle ratio of 2.7 times on a proved basis and 3.3 times on a proved plus probable basis. Excluding changes in future development capital, FD&A costs were $10.92 per boe proved and $9.15 per boe proved plus probable.
- All-in 2005 production replacement cost was $16,805 per boe per day.

FINANCIAL

- Petroleum and natural gas revenue was $68.1 million for the year compared to $9.5 million during the prior year.
- Funds generated from operations for the year was $36.0 million ($0.96 per diluted share) compared to $4.8 million ($0.14 per diluted share) during the prior year for an increase of 658 percent while funds generated from operations per diluted share increased 586 percent during the same period.
- Net earnings for the year were $15.0 million ($0.40 per diluted share) compared to $1.7 million ($0.05 per diluted share) during the prior year, an increase of 700 percent per diluted share during the same period.
- Capital expenditures totaled $85.5 million for the year including $19.5 million in land capture and seismic data acquisition to provide future growth opportunities.
- Bank debt and working capital deficiency was $9.3 million at December 31, 2005 compared to the $45 million demand revolving operating credit facility available at year end, which was increased to $70 million subsequent to year end.

RESULTS OF OPERATIONS

Production

The following is a summary of daily production for the quarterly periods indicated:

	2005				2004	
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3 [(1)]
Natural gas (mcf/d)	**24,942**	**17,255**	**12,943**	**12,170**	6,365	3,806
Crude oil (bbls/d)	**316**	**272**	**267**	**242**	252	275
Natural gas liquids (bbls/d)	**88**	**66**	**66**	**89**	57	40
Total production *(boe/d)*	**4,561**	**3,214**	**2,490**	**2,359**	1,370	949

(1) Period from July 2, 2004 to September 30, 2004.

	2005	Period from July 2, December 31, 2004
Annual Production		
Natural gas (mcf)	**6,155,314**	931,898
Crude oil (bbls)	**100,135**	48,179
Natural gas liquids (bbls)	**28,119**	8,929
Total production (boe)	**1,154,140**	212,424
Daily Production		
Natural gas (mcf/d)	**16,864**	5,092
Crude oil (bbls/d)	**274**	263
Natural gas liquids (bbls/d)	**77**	49
Total production (boe/d)	**3,162**	1,161

ProEx's production for the year ended December 31, 2005 averaged 3,162 boe per day. The production was comprised of 274 bbls per day of crude oil, 77 bbls per day of natural gas liquids and 16,864 mcf per day of natural gas. Production was divided between the Fort St. John Plains region of British Columbia at 1,010 boe per day, the Gundy and Town areas in the Foothills of British Columbia at 1,221 boe per day, 919 boe per day in the West Beg area also in the Foothills of British Columbia and 12 boe per day from the Halkirk area in Alberta which was sold in the first quarter of 2005. Production increased substantially over the 1,161 boe per day recorded in the prior year due to the success of the 2005 drilling and completion program.

(boe/d)	**Production**
Production Reconciliation	
Production fourth quarter 2004	1,370
Disposition of Alberta assets [(1)]	(199)
Decline on base production	(194)
Exploration program production additions during 2005	5,085
Decline on new 2005 production	(1,501)
Production fourth quarter 2005	4,561

(1) Disposition of the Halkirk, Alberta asset occurred in January 2005.

Cost of Production Additions

During 2005, the Company added 5,085 boe per day of new production from its drilling and completion program. With a capital investment program of $85.5 million, this results in production being efficiently added at a cost of $16,805 per boe per day.

Producing Areas

The following table summarizes the Company's average production by producing areas for the year ended December 31, 2005 and the prior year.

(boe/d)	**2005**	Period from July 2 to December 31, 2004
Fort St. John Plains, British Columbia	**1,010**	669
Foothills, British Columbia (Gundy and Town areas)	**1,221**	281
Foothills, British Columbia (West Beg area)	**919**	-
Halkirk, Alberta	**12**	211
Total daily production	**3,162**	1,161

COMMODITY PRICING

Average Benchmark Prices

	2005	Period from July 2 to December 31, 2004
Natural gas – Station #2 *(Cdn $/mcf daily index)*	**8.62**	6.41
Natural gas – AECO *(Cdn $/mcf daily index)*	**8.80**	6.38
Natural gas – AECO *(Cdn $/mcf monthly index)*	**8.56**	6.94
Exchange rate *(US$/Cdn$)*	**1.2114**	1.2639

ProEx Realized Prices

	2005	Period from July 2 to December 31, 2004
Natural gas ($/mcf)	**9.70**	6.97
Crude oil ($/bbl)	**66.49**	54.49
Natural gas liquids ($/bbl)	**62.32**	44.59

Commodity pricing through 2005 continued upward from the record highs of 2004 as West Texas Intermediate ("WTI") crude oil established a new record in the third quarter as it averaged US$65.55 per barrel and both the New York Mercantile Exchange ("NYMEX") gas price and Canadian Alberta Energy Company interconnect with the TransCanada Alberta system ("AECO") gas price jumped to record averages of US$14.07 per mmbtu and Cdn$11.79 per gigajoule ("gj") respectively in the fourth quarter.

Rising oil prices helped support natural gas during the first quarter of 2005 as reduced demand for space heating resulted from warmer than normal weather throughout much of North America. As the market rolled through the second quarter, continued warmer than normal weather created high cooling demand and limited the markets ability to refill natural gas storage as gas was burned for incremental power generation. Crude oil prices also continued

upward during this time as inventories of crude oil and refined products remained low while the market expected inventories to increase prior to the high demand summer season. Hurricane damage to natural gas producing infrastructure in the southeastern United States ("U.S.") impacted the third and fourth quarters creating concerns about the adequacy of supply in advance of the winter heating season. As a result of hurricane Katrina, the loss of Gulf of Mexico production and physical flooding of the "Henry Hub" market center in Louisiana, gas processing and oil refining facilities reduced supply to the point where significant price increases were the only way to reduce demand and balance the market. When the fourth quarter began, natural gas storage volumes were thought to be insufficient to meet winter demand which maintained upward pressure on natural gas prices until mid December when long range weather forecasts for predominantly warm weather and minimal storage withdrawls all but eliminated the supply risk for the balance of winter. WTI oil prices closed 2005 near an all time high as strong demand and relatively low inventories maintained upward pricing pressure.

As we look ahead to 2006, we expect to see WTI oil prices remain in the US$50.00 to US$60.00 per barrel range and natural gas at AECO to average between $6.00 and $8.00 per gj.

Natural Gas Pricing

The U.S. natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of ProEx's natural gas is sold at pricing based at one of the Alberta or British Columbia hubs. ProEx typically sells 50 percent of its natural gas production on monthly indexes and 50 percent on daily indexes.

Natural Gas Production and Prices by Province

	2005		Period from July 2 to December 31, 2004	
	Mcf/d	$/Mcf	Mcf/d	$/Mcf
Alberta (1)	**43**	**6.52**	956	6.86
British Columbia	**16,821**	**9.70**	4,136	7.05
Total production and average sales price	**16,864**	**9.70**	5,092	6.97

(1) ProEx disposed of its Halkirk, Alberta assets in January 2005.

British Columbia Natural Gas Prices

	2005	Period from July 2, to December 31, 2004
NYMEX *(US $/mmbtu 12 month average – last 3 Days)*	**8.55**	6.35
Less: Station #2 basis differential to Henry Hub *(US $/mmbtu)*	**(1.50)**	(1.35)
Station #2 *(US $/mmbtu)*	**7.05**	5.00
Average exchange rate	**1.2114**	1.2639
Station #2 price *(Cdn $/mcf daily index)* (1)	**8.62**	6.41
Premium: ProEx realized price vs spot	**1.08**	0.64
ProEx average British Columbia field price *(Cdn $/mcf)*	**9.70**	7.05

(1) Converted from $/mmbtu to $/mcf using the Energy and Utilities Board conversion factor.

Petroleum and Natural Gas Revenues

Petroleum and natural gas revenues of $68.1 million for 2005 was up 615 percent over the $9.5 million in revenues recorded in the prior year. ProEx recorded $59.7 million in natural gas sales ($6.5 million in the prior year), $6.7 million in crude oil sales ($2.6 million in the prior year), and $1.7 million in natural gas liquid sales ($0.4 million in the prior year). Increased petroleum and natural gas revenues over the prior year are a result of the prior year being a partial year and significant production and commodity price increases.

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Revenues by product		
Natural gas	**59,676**	6,496
Crude oil	**6,658**	2,625
Natural gas liquids	**1,752**	398
Total Petroleum and natural gas revenues	**68,086**	9,519

Royalties

Royalty rates increased to 29.6 percent during 2005 compared to 25.0 percent during the prior year. The higher royalty rates are the result of the disposition of Alberta production which incurred lower royalty rates, the increase in Foothills British Columbia production which incurs higher royalty rates and increased production on farm-in lands which incur gross overriding royalties. Management anticipates that the average royalty rates for 2006 will be between 30 and 35 percent.

($ thousands, except where otherwise indicated)	**2005**	Period from July 2 to December 31, 2004
Royalties		
- Crown	**16,163**	1,802
- Freehold and overriding	**3,973**	583
Total royalties	**20,136**	2,385
Total royalties ($/boe)	**17.45**	11.23
Average royalty rate (%)	**29.6**	25.0
Royalties by Product		
Natural gas royalties	**18,342**	1,753
$/boe	**17.88**	11.29
Average natural gas royalty rate (%)	**30.7**	27.0
Natural gas liquids royalties	**413**	123
$/boe	**14.69**	13.78
Average natural gas liquids royalty rate (%)	**23.6**	30.9
Crude oil royalties	**1,381**	509
$/boe	**13.79**	10.56
Average crude oil royalty rate (%)	**20.7**	19.4

Operating Expenses

Operating expenses for 2005 were $6.2 million, compared to $1.5 million in the prior year. The increase is due to higher production in 2005 compared to 2004. On a boe basis, operating expenses for 2005 decreased 29 percent to $5.34 from $6.87 in 2004 due to increased operating efficiencies and the sale of the Alberta properties in early 2005. Management anticipates 2006 normalized operating expenses to be in the $5.00 to $5.25 per boe range.

($ thousands, except where otherwise indicated)	**2005**	Period from July 2 to December 31, 2004
Operating expenses - natural gas properties	**5,351**	711
$/boe	**5.01**	4.78
Operating expenses – crude oil properties	**813**	748
$/boe	**9.53**	11.75
Operating expenses – all properties	**6,164**	1,459
$/boe	**5.34**	6.87

Transportation Expenses

Transportation expenses were $4.0 million for 2005 compared to $0.5 million in the prior year. The increase in transportation expenses in the year over the prior year is due to an increase in production volumes. On a boe basis, transportation expenses were $3.47 per boe in 2005 compared to $2.30 per boe in 2004. The increase is due to higher Alberta production in 2004 which incurred lower transportation fees. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Total transportation expenses	**4,008**	489
$/boe	**3.47**	2.30

Operating Netbacks by Product

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas, crude oil and all properties for the year and for the prior year.

	2005	Period from July 2 to December 31, 2004
Natural gas properties ($/mcf)		
Sales price	**9.76**	7.09
Royalties	**(2.98)**	(1.84)
Transportation expenses	**(0.59)**	(0.46)
Operating expenses	**(0.83)**	(0.80)
Operating netback – natural gas properties	**5.36**	3.99

	2005	Period from July 2 to December 31, 2004
Crude oil properties ($/bbl)		
Sales price	**64.08**	50.08
Royalties	**(11.75)**	(11.64)
Transportation expenses	**(2.26)**	(1.20)
Operating expenses	**(9.53)**	(11.75)
Operating netback – oil properties	**40.54**	25.49

	2005	Period from July 2 to December 31, 2004
All properties ($/boe)		
Sales price	**58.99**	44.81
Royalties	**(17.45)**	(11.23)
Transportation expenses	**(3.47)**	(2.30)
Operating expenses	**(5.34)**	(6.87)
Operating netback – all properties	**32.73**	24.41

General and Administrative Expenses

For the year, general and administrative expenses ("G&A") were $1.1 million ($0.98 per boe) compared to $0.4 million ($1.67 per boe) for the prior year. G&A for the year was comprised of $0.7 million in direct G&A expenses, $2.8 million in technical service fees from Progress under the Technical Services Agreement (see Relationship with Progress herein) less $1.6 million in recoveries and $0.8 million in capitalized G&A. The increase in G&A expense was the result of a full year of expenses compared to the shortened period in 2004. The Company also incurred higher technical service fees from Progress due to the higher proportion of ProEx production to the combined production of both Progress and ProEx (computed in accordance to the Technical Services Agreement). The higher gross G&A was partially offset by higher recoveries driven off higher capital spending during the year versus the prior year and higher capitalized G&A expense incurred through the technical service fees. The reduction in G&A per boe was the result of significantly higher production volumes during the year versus the prior year. Management forecasts G&A expenses for 2006 to average in the $1.00 to $1.10 per boe range.

($ thousands)	2005	Period from July 2 to December 31, 2004
Direct expenses	**701**	264
Technical services fee from Progress	**2,759**	556
Gross G&A	**3,460**	820
Recoveries	**(1,582)**	(273)
Capitalized expenses	**(752)**	(193)
Total G&A	**1,126**	354
Total G&A *($boe)*	**0.98**	1.67

Stock Based Compensation Expense

During the year, the Company expensed $0.4 million in stock based compensation expense related to outstanding stock options and Class B performance shares, compared to $0.2 million in the prior year. The increase is due to the inclusion in 2005 of a full year of compensation expense compared to the partial year in 2004.

Depletion, Depreciation and Accretion Expense

For the year, depletion and depreciation of capital assets and the accretion of the asset retirement obligations ("DD&A") was $11.4 million compared to $2.0 million for the prior year. On a boe basis, DD&A expense for the year was $9.89 compared to $9.36 for the prior year. This was a result of slightly higher proved finding and development costs during 2005 compared to 2004.

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Depletion	**11,298**	1,915
Depreciation	**2**	
Accretion	**117**	72
Total depletion, depreciation and accretion	**11,417**	1,987
DD&A ($/boe)	**9.89**	9.36
Depletion and depreciation rate (%)	**3.44**	3.87

Future Income Taxes

Future income tax expense for 2005 was $9.6 million compared to $1.0 million in the prior year. The increase is due to higher earnings in 2005.

The Company has approximately $118.0 million in tax pools to shelter taxable income in future years. The tax pools are as follows:

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Canadian Exploration Expense	**32,000**	10,000
Canadian Development Expense	**25,500**	7,500
Canadian Oil and Gas Property Expense	**31,500**	36,500
Undepreciated Capital Cost	**23,000**	8,500
Other	**6,000**	3,000
Total tax pools	**118,000**	65,500

Net Earning and Funds Generated from Operations

Net earnings were $15.0 million for the year compared to $1.7 million for the prior year. Basic net earnings per share for the year was $0.49 per share ($0.06 per share in 2004), while diluted net earnings per share for the year was $0.40 ($0.05 per share in 2004). Funds generated from operations were $36.0 million for the year, compared to $4.8 million in the prior year. Funds generated from operations per basic share for the year was $1.17 per share ($0.18 per share in 2004), while funds generated from operations per diluted share for the year was $0.96 ($0.14 per share in 2004). The substantially higher net income and funds generated from operations in the current year is a result of the shorter reporting period in 2004, in addition to substantially higher production volumes and commodity prices. On a per boe basis, net income increased from $8.08 per boe in the prior year to $13.01 for the current year, reflecting a 61 percent growth over the prior year. Funds generated from operations increased 40 percent on a boe basis from $22.38 for the prior year to $31.23 per boe in the current year.

The following table summarizes the netbacks, funds generated from operations and net earnings on a barrel of oil equivalent basis for the year and the prior year:

($/boe)	**2005**	Period from July 2 to December 31, 2004
Petroleum and natural gas revenues	**58.99**	44.81
Royalties	**(17.45)**	(11.23)
Interest income	**0.02**	0.36
	41.56	33.94
Operating expenses	**(5.34)**	(6.87)
Transportation expenses	**(3.47)**	(2.30)
Operating netback	**32.75**	24.77
General and administrative expenses	**(0.98)**	(1.67)
Interest expenses	**(0.10)**	(0.15)
Asset retirement expenditures (1)	**(0.33)**	(0.57)
Capital taxes	**(0.11)**	-
Funds generated from operations	**31.23**	22.38
Asset retirement expenditures (1)	**0.33**	0.57
Stock based compensation expense	**(0.39)**	(0.74)
Depletion, depreciation and accretion expenses	**(9.89)**	(9.36)
Net earnings before taxes	**21.28**	12.85
Future income taxes	**(8.27)**	(4.77)
Net earnings	**13.01**	8.08

(1) Actual asset retirement costs incurred during the period are classified for cash flow purposes on the statement of cash flows as an operating item, however these costs are not an expense of the period and are therefore added back for purposes of determining net earnings.

COMMON SHARE INFORMATION

(thousands)	2005	2004
Weighted average outstanding common shares		
- Basic	**30,687**	27,040
- Diluted	**37,522**	33,257
Outstanding securities at December 31,		
- Common shares	**32,998**	27,450
- Common share options	**472**	224
- Common share warrants	**6,585**	7,221
- Diluted common shares outstanding	**40,055**	34,895
- Class B performance shares	**695**	701
Outstanding securities at February 27, 2006		
- Common shares	**32,999**	
- Common share options	**552**	
- Common share warrants	**6,583**	
- Diluted common shares outstanding	**40,134**	
- Class B performance shares	**695**	

Per Share Information

($ thousand, except per share amounts)	2005	Period from July 2 to December 31, 2004
Net earnings	**15,015**	1,717
Net earnings per share		
- Basic	**0.49**	0.06
- Diluted	**0.40**	0.05
Funds generated from operations	**36,044**	4,755
Funds generated from operations per share		
- Basic	**1.17**	0.18
- Diluted	**0.96**	0.14
Proved plus probable reserves *(mboe)*	**15,028**	6,844
Proved plus probable reserves per thousand shares *(boe)*		
- Basic *(1)*	**455**	249
- Diluted *(2)*	**375**	196
Average Production (boe/d)	**3,162**	1,161
Average Production per million shares *(boe/d)*		
- Basic *(3)*	**103.04**	42.94
- Diluted *(4)*	**84.27**	34.91
Fourth quarter production (boe/d)	**4,561**	1,370
Fourth quarter production per million shares *(boe)*		
- Basic *(1)*	**138.22**	49.91
- Diluted *(2)*	**113.87**	39.26

(1) Calculated using outstanding common shares at end of period.
(2) Calculated using outstanding common shares, options and warrants at end of period.
(3) Calculated using the weighted average outstanding common shares during the period.
(4) Calculated using the weighted average outstanding common shares, options and warrants at end of period.

On a per share basis, net earnings for the year increased 717 percent over the prior year, while on a diluted basis, net earnings per share increased 700 percent. Funds generated from operations per basic share increased by 550 percent during the year while funds generated from operations per diluted share increased 586 percent during the same period.

Average production per million basic shares increased 140 percent during the year while average production per one million diluted shares increased 141 percent during the same period.

Proved plus probable reserves per thousand basic shares increased of 83 percent over the prior year while proved plus probable reserves per one thousand diluted shares increased 91 percent during the same period.

NET ASSET VALUE BEFORE TAX(1)

ProEx's net asset value per share at December 31, 2005 was $7.71 per basic share ($2.91 per basic share in 2004) and on a diluted basis $6.68 per share ($2.61 per diluted share in 2004) using GLJ Petroleum Consultants ("GLJ") forecasted prices, and $8.49 per basic share and $7.32 per diluted share ($3.24 and $2.87 respectively per share in 2004) using GLJ constant prices.

	2005		2004	
($ thousands)	**Constant Price**	**Forecast Price**	Constant Price	Forecast Price
Proved plus probable reserve value *(10% discount before tax)* (2)	**240,122**	**214,326**	81,223	72,319
Undeveloped acreage (3)	**40,000**	**40,000**	20,000	20,000
Seismic(4)	**10,000**	**10,000**	-	-
Working capital deficiency	**(9,275)**	**(9,275)**	(11,681)	(11,681)
Asset retirement obligations(5)	**(672)**	**(672)**	(715)	(715)
Net asset value - Basic	**280,175**	**254,379**	88,827	79,923
Exercise of stock options and warrants	**13,104**	**13,104**	11,318	11,318
Net asset value - Diluted	**293,279**	**267,483**	100,145	91,241
Common shares outstanding				
-Basic	**32,998**	**32,998**	27,450	27,450
-Diluted	**40,055**	**40,055**	34,895	34,895
Net asset value per common share ($)				
-Basic	**8.49**	**7.71**	3.24	2.91
-Diluted(6)	**7.32**	**6.68**	2.87	2.61

(1) The Company's net asset value before tax is measured with reference to the present value of future estimated net cash flows from reserves estimated by GLJ, the independent reserve engineers, and including land, seismic data, adjustments for working capital deficiency, asset retirement obligations and bank debt at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

(2) Reserve values are based on before tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators, GLJ using their future commodity price forecast as presented in the pricing assumptions on page R9 and R10.

(3) Due to the significant increase in land values in northeast British Columbia during the past twelve months, land values are based on internal estimates of market values further substantiated by recent sales of similar properties in the same general area.

(4) Seismic inventory values are an internal estimate of replacement value.

(5) Proved plus probable reserve value includes $0.8 million (2004 - $1.2 million) of asset retirement obligations on wells with assigned reserves.

(6) Calculated using outstanding common shares, options and warrants at year-end.

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Investment

During the year the Company invested approximately $94.1 million ($85.5 million net of property dispositions) with the drilling of 45 gross wells (28.6 net) for a success rate of 94 percent. In the first quarter of 2005, the Company sold its assets in the Halkirk, Alberta area for proceeds of $12.0 million and acquired lands in the Bernadet area of northeastern British Columbia in the third quarter at a cost of $3.4 million. The following table summarizes the capital investments for the year and the prior year.

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Land acquisitions and retention	**7,682**	5,139
Geological and geophysical	**11,781**	851
Drilling and completions	**55,872**	19,205
Equipping and facilities	**18,779**	6,655
Corporate assets	**-**	10
Total exploration and development capital	**94,114**	31,860
Net property acquisitions (disposition)	**(8,660)**	4,506
Total capital expenditures	**85,454**	36,366

Drilling results

	2005		Period from July 2 to December 31, 2004	
	Gross	**Net**	Gross	Net
Crude oil	**4**	**0.8**	1	0.2
Natural gas	**37**	**26.2**	18	13.4
Dry and abandoned	**4**	**1.6**	-	-
Total	**45**	**28.6**	19	13.6
Success rate	**91%**	**94%**	100%	100%

Undeveloped Land

ProEx has undeveloped land at year end of approximately 161,000 net acres and in addition has access to approximately 46,500 acres of option lands for a total net acreage under its control of approximately 207,500. Approximately 135,000 net acres (84 percent) of the undeveloped lands are in the Foothills region of northeast British Columbia and ProEx's average interest in these lands is 73 percent. Including option lands, ProEx has 162,000 net acres or 78 percent of its acreage in the Foothills region. The balance of the northeast British Columbia undeveloped lands are in the Fort St. John Plains region where the Company has an average working interest of 19 percent.

Undeveloped Land Additions

ProEx has purchased, acquired through farm-in or bought at Crown land sales approximately 50,000 net acres during the year. These acquisitions represent an increase in net undeveloped lands of approximately 60 percent in the Foothills region. ProEx has an average working interest in its undeveloped land base of 50 percent which is an

increase from 44 percent in 2004. ProEx continues to generate opportunities to earn land through farm-ins with 70 sections of option lands available to it at December 31, 2005. Over the next twelve months, seven percent of ProEx net undeveloped acreage will be subject to expiry. With an active drilling program, ProEx anticipates minimal undeveloped acres expiring in 2006.

Option Land Additions

At December 31, 2005, ProEx has 46,567 gross acres of land in its core areas in British Columbia on which it has the option to earn an interest. Of these options lands, approximately 57 percent are in the Foothills region of British Columbia while the balance of these lands are in the Fort St. John Plains region of British Columbia. These lands are subject to various agreements whereby the Company must perform certain activities to earn an interest in the lands. The term of these agreements extend through various terms to August 2006.

	2005		2004	
	Gross	**Net**	Gross	Net
Alberta	-	-	13,441	11,470
British Columbia	**321,460**	**160,869**	271,036	112,204
Total owned undeveloped land	**321,460**	**160,869**	284,477	123,674
Total controlled British Columbia option land	**46,567**		82,405	

Finding & Development Costs

Advisory

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development capital generally will not reflect total finding and development costs related to reserve additions for that year.

During 2005, the exploration and development program resulted in total reserve additions (after revisions) of 8.1 million boe on a proved basis, and 9.7 million boe on a proved plus probable basis resulting in the total exploration and development program finding and development costs ("F&D") of $11.59 per boe proved and $9.66 per boe proved plus probable. After incorporating the change in future development capital, the exploration and development program generated finding and development costs of $12.60 per boe proved and $10.33 per boe proved plus probable. The total capital program including net dispositions during the year and the change in future development capital, generated finding, development and net acquisition costs ("FD&A") of $11.97 per boe proved and $9.85 per boe proved plus probable.

2005 Finding & Development Costs and Finding, Development & Net Acquisition Costs

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ thousands)	*(mboe)*	*($/boe)*	*(mboe)*	*($/boe)*
F&D exploration and development program before revisions	94,114	7,883	11.94	9,845	9.56
F&D exploration and development program after revisions (a)	94,114	8,120	11.59	9,743	9.66
Change in proved future development capital (b)(1)	8,189	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)(1)	6,553	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	102,303	8,120	12.60	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	100,667	n/a	n/a	9,743	10.33
Net acquisition/disposition activity (f)	(8,660)	(298)	(29.06)	(405)	(21.38)
Total 2005 proved FD&A costs including future development capital (d+f)	93,643	7,822	11.97	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development capital (e+f)	92,007	n/a	n/a	9,338	9.85

2004 Finding & Development Costs and Finding, Development & Net Acquisition Costs

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ thousands)	*(mboe)*	*($/boe)*	*(mboe)*	*($/boe)*
F&D exploration and development program before revisions	31,860	3,552	8.97	4,808	6.63
F&D exploration and development program after revisions (a)	31,860	3,500	9.10	4,654	6.85
Change in proved future development capital (b)(1)	3,764	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)(1)	6,378	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	35,624	3,500	10.18	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	38,238	n/a	n/a	4,654	8.22
Net acquisition/disposition activity (f)	4,506	–	n/c (2)	–	n/c (2)
Total 2004 proved FD&A costs including future development Capital (d+f)	40,130	3,500	11.47	n/a	n/a
Total 2004 proved plus probable FD&A costs including future development capital (e+f)	42,744	n/a	n/a	4,654	9.18

(2) The acquisition activity during the period consisted of undeveloped land with no associated reserves.

Combined 2004 and 2005 Finding & Development Costs and Finding, Development & Net Acquisition Costs

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ thousands)	*(mboe)*	*($/boe)*	*(mboe)*	*($/boe)*
F&D exploration and development program before revisions	125,974	11,435	11.02	14,653	8.60
F&D exploration and development program after revisions (a)	125,974	11,620	10.84	14,397	8.75
Change in proved future development capital (b)[1]	11,953	n/a	n/a	n/a	n/a
Change in proved plus probable future development capital (c)[1]	12,931	n/a	n/a	n/a	n/a
Proved F&D including change in future development capital (d) = (a+b)	137,927	11,620	11.87	n/a	n/a
Proved plus probable F&D including change in future development capital (e) = (a+c)	138,905	n/a	n/a	14,397	9.65
Net acquisition/disposition activity (f)	(4,154)	(298)	(13.94)	(405)	(10.26)
Total 2004 and 2005 proved FD&A costs including future development capital (d+f)	133,773	11,322	11.82	n/a	n/a
Total 2004 and 2005 proved plus probable FD&A costs including future development capital (e+f)	134,751	n/a	n/a	13,992	9.63

(1) *Reconciliation of Changes in Future Development Capital*

($ thousands)	*Proved*	*Change*	*Proved Plus Probable*	*Change*
July 2, 2004	*1,118*		*1,729*	
		3,764		*6,378*
January 1, 2005	*4,882*		*8,107*	
		8,189		*6,553*
January 1, 2006	*13,071*		*14,660*	

Production Replacement

The Company's capital investment program during the year replaced production by a factor of 6.8 times on a proved basis and 8.1 times on a proved plus probable basis.

	2005	Period from July 2 to December 31, 2004
Production *(mboe)*	**1,154**	424[1]
Proved reserve additions after revisions of prior periods and net dispositions *(mboe)*	**7,822**	3,520
Proved replacement ratio	**6.8**	8.3
Proved plus probable reserve additions after revision of prior periods and net	**9,338**	4,654
Proved plus probable replacement ratio	**8.1**	11.0

(1) *Annualized production*

Recycle Ratio

The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per boe of oil equivalent to that year's reserve FD&A costs.

	2005	Period from July 2 to December 31, 2004
Operating netbacks *($/boe)*	**32.75**	24.77
Proved FD&A costs after revisions of prior periods and including the change in future development capital *($/boe)*	**11.97**	11.47
Proved reinvestment efficiency ratio	**2.7**	2.2
Proved plus probable FD&A costs after revisions of prior periods and including the change in future development capital *($/boe)*	**9.85**	9.18
Proved plus probable reinvestment efficiency ratio	**3.3**	2.7

CAPITALIZATION AND CAPITAL RESOURCES

The Company's total capitalization was $558 million at December 31, 2005 with a market value of common shares representing 97 percent of total capitalization and total debt representing 2 percent of total capitalization. The market value of the Company's common shares increased to $541.2 million compared to $225.1 million as at December 31, 2004.

(thousands except per share amounts)	%	2005	%	2004
Common shares outstanding		**32,998**		27,450
Share price [(1)]		**16.40**		8.20
Total market capitalization	**97**	**541,167**	93	225,090
Working capital deficiency		**9,275**		11,681
Bank debt		**-**		-
Total debt	**2**	**9,275**	5	11,681
Asset retirement obligations	**-**	**1,426**	1	1,936
Future income tax liability (asset)	**1**	**6,259**	1	(2,291)
Total capitalization	**100**	**558,127**	100	236,416
Total debt to total capitalization (%)		**2**		5

(1) Represents the closing price on the TSX on December 31.

The Company has a $45 million credit facility available on which no funds were drawn at December 31, 2005. At December 31, 2005 the Company had a working capital deficit of $9.3 million resulting in total net debt of $9.3 million. The ratio of total net debt as at December 31, 2005 to 2005 funds generated from operations was 0.3 times and the ratio of total net debt as at December 31, 2005 to the annualized fourth quarter funds generated from operations was 0.1 times. The 2006 capital program will be funded by funds generated from operations and bank debt. Subsequent to the year end, the Company increased its demand revolving operating credit facility to $70 million.

Investing Program Funding

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Cash and short term investments, beginning of period	**2,112**	-
Funds generated from operations	**36,044**	4,755
Changes in non-cash operating working capital	**(3,851)**	13,793
Issue of common shares (net of share issue costs)	**51,816**	29,930
Decrease in bank debt	-	(10,000)
Less cash and short term investments, end of period	**(667)**	(2,112)
Capital expenditures during the period	**85,454**	36,366

The Company's 2005 capital investment program was funded by funds generated from operations and two equity offerings during the year. On January 27, 2005 the Company sold its Alberta assets for proceeds of approximately $12.0 million. On February 25, 2005 the Company issued 2.5 million common shares at a price of $9.10 per common share resulting in gross proceeds of $22.8 million ($21.6 million net of issue costs). On August 23, 2005 the Company issued 2.5 million common shares at a price of $12.40 per common share resulting in gross proceeds of $31.0 million ($29.5 million net of issue costs).

Bank Facility

The Company has a $45 million demand revolving operating credit facility. The Company's credit facility is with a Canadian bank and is reviewed twice per year. The facility is a borrowing base facility that is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment. No funds were drawn on the available credit facility at year end in 2005 and 2004. Subsequent to the year end, the Company increased its demand revolving operating credit facility to $70 million with the same terms as disclosed above.

Working Capital

The capital intensive nature of the Company's activities may create a negative working capital position in quarters with high levels of capital investment. Working capital deficiency decreased from $11.9 million as at December 31, 2004 to $9.2 million as at December 31, 2005 due to increased accrued accounts receivable as a result of increased commodity prices and production in December 2005 compared to December 2004.

Substantially all of the Company's petroleum and natural gas production is marketed by Progress Energy Trust under standard industry terms and in accordance with the terms of the Technical Services Agreement. Accounts payable consist of amounts payable to suppliers, field operating activities and capital spending activities. These invoices are processed within the Company's normal payment period. At December 31, 2005 the Company had no material accounts receivable that it deemed uncollectible.

The Company actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting funds generated from operations. Should circumstances affect funds generated from operations in a detrimental way, the Company is capable of reducing capital activity levels.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As part of the Company's land capture strategy, it will commit to industry partners to drill wells, and or shoot seismic in order to earn positions in contiguous land blocks. As at December 31, 2005, ProEx had commitments to drill and complete three wells costing in aggregate approximately $5.1 million (net) in 2006 which will earn lands from area competitors in the Foothills region of northeast British Columbia. These commitments are scheduled in the Company's 2006 capital investment plans.

The Company must pay Crown royalties, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amount paid with respect to these burdens will depend on the future ownership, production, commodity prices and regulatory environment at the time.

At the time of writing, the Company has a deal in principle on a five year commitment for raw gas transmission and treatment on the regulated British Columbia natural gas system. Final details are currently being negotiated and the contractual obligation amounts presented below reflect this pending agreement.

($ thousands)	Total	2006	2007	2008	2009	2010	2011
Farm-in commitments	5,070	5,070	-	-	-	-	-
Gas transmission and treatment (1)	44,130	6,509	7,685	7,685	7,440	7,019	4,199
Drilling rig commitments	3,372	656	1,686	1,030	-	-	-
Operating leases	981	918	63				
Total contractual obligations	53,553	13,153	9,434	8,715	7,440	7,019	4,199

(1) The Company has reflected the contractual option to reduce contracted volume amounts by 20 percent per year in the final two years of the contract in the numbers presented above.

OFF-BALANCE SHEET ARRANGEMENTS

ProEx has no off-balance-sheet arrangements.

OUTLOOK AND 2006 BUDGET

By combining an extensive exploration and development drilling inventory, low finding costs and balance sheet strength, we are well positioned to capitalize on our opportunities in 2006 and beyond. Our exploration land base in northeast British Columbia has grown very rapidly to over 200,000 net acres under our control. With the results from our 2005 drilling program and a total of approximately 865 square kilometers of 3-D seismic data in the Foothills, we have developed an extensive knowledge of the subsurface and the opportunities to expand the Halfway tight gas play as well as develop new concepts in the Cretaceous section. Included in our plans for 2006 is a deep Debolt test in the Julienne area. We plan to spud this well at the beginning of the second quarter and drill through breakup.

We expect to invest approximately $85 million in 2006, primarily in the Foothills region in northeast British Columbia. Approximately 25 percent of the capital program will be invested in land capture and seismic data acquisition to continuously expand our inventory of drilling opportunities. We are targeting average production for 2006 of between 6,300 to 6,700 boe per day and exiting the year between 7,000 to 7,500 boe per day. We anticipate

funding our growth program with funds generated from operations and the existing bank debt facility which was increased to $70 million subsequent to year end.

2006 SENSITIVITIES

Based on the above assumptions, the following sensitivities are provided to demonstrate the impact on funds generated from operations and net earnings of changes in commodity prices, and the Canadian currency.

($ thousand)	Funds generated from operations	Net earnings
Impact on the year ended December 31, 2006		
- Change in West Texas Intermediate oil price by US$1.00 per barrel	150	80
- Change in average field price of natural gas by Cdn $1.00 per mcf	7,900	4,400
- Change in value of Cdn dollar compared to US dollar by Cdn $0.01	700	400

SELECTED QUARTERLY INFORMATION AND FOURTH QUARTER ANALYSIS

	2005				2004	
	Q4	Q3	Q2	Q1	Q4	Q3[1]
Operational Results						
Production						
– Natural gas *(mcf/d)*	**24,942**	**17,255**	**12,943**	**12,170**	6,365	3,806
– Crude oil *(bbls/d)*	**316**	**272**	**267**	**242**	252	275
– Natural gas liquids *(bbls/d)*	**88**	**66**	**66**	**89**	57	40
– Total production *(boe/d)*	**4,561**	**3,214**	**2,490**	**2,359**	1,370	949
Pricing						
– Natural gas *($/mcf)*	**11.96**	**9.54**	**7.91**	**7.09**	7.32	6.38
– Crude oil *($/bbl)*	**67.99**	**74.62**	**63.48**	**58.47**	56.28	52.83
– Natural gas liquids *($/bbl)*	**69.25**	**69.23**	**59.38**	**52.32**	44.69	44.44
Selected Financial Results ($ thousands, except per share amounts)						
Petroleum and natural gas revenue	**29,984**	**17,434**	**11,217**	**9,452**	5,824	3,695
Royalties	**9,561**	**5,291**	**2,949**	**2,335**	1,524	860
Operating expenses	**1,878**	**1,651**	**1,454**	**1,181**	798	660
General and administrative expenses	**504**	**247**	**303**	**74**	239	115
Funds generated from operations	**16,501**	**8,953**	**5,589**	**5,001**	2,873	1,882
Depletion, depreciation and accretion expense	**4,062**	**2,846**	**2,442**	**2,067**	1,283	705
Net earnings	**7,775**	**3,585**	**1,919**	**1,737**	1,054	663
– Basic per share	**0.24**	**0.11**	**0.06**	**0.06**	0.04	0.02
– Diluted per share	**0.20**	**0.09**	**0.05**	**0.05**	0.03	0.02
Capital Spending						
– Exploration and development	**28,713**	**24,425**	**11,101**	**29,875**	23,143	8,706
– Net acquisitions and dispositions	**17**	**3,403**	**10**	**(12,090)**	4,440	66
– Corporate assets	**-**	**-**	**-**	**-**	11	-
Total capital expenditures	**28,730**	**27,828**	**11,111**	**17,785**	27,594	8,772
Bank debt and working capital deficiency (surplus)	**9,275**	**(2,915)**	**8,455**	**2,905**	11,681	(13,046)
Shareholders' equity	**117,951**	**110,008**	**75,505**	**73,500**	49,674	48,543
Common shares outstanding	**32,997**	**32,974**	**29,950**	**29,950**	27,450	27,454

(1) represents the period from July 2, 2004 to September 30, 2004.

Production

Production during the fourth quarter of 2005 increased by 42 percent to 4,561 boe per day compared to 3,214 boe per day in the prior quarter. The production increase was the result of successful drilling during the third quarter of 2005. Production additions were generated primarily in the West Beg area of the Foothills region of northeast British Columbia with production that increased from 978 boe per day in the prior quarter to 2,294 boe per day in the fourth quarter. Production increased by 233 percent from the 1,370 boe per day recorded in the fourth quarter of 2004 due to the success of the 2005 capital program.

Petroleum and Natural Gas Revenues

Petroleum and natural gas revenues for the fourth quarter of 2005 increased 72 percent to $29.9 million compared to the prior quarter of $17.4 million. Realized natural gas prices increased 25 percent to $11.96 per mcf in the fourth quarter compared to $9.54 per mcf in the third quarter. This price increase, combined with the production growth discussed above resulted in substantial revenue growth. Revenues increased by 415 percent from the $5.9 million recorded in the fourth quarter of 2004 due to higher production and the increase in natural gas prices.

Royalties

Royalties for the fourth quarter of 2005 increased 81 percent to $9.6 million over the prior quarter of $5.3 million. The average royalty rate increased from 30.3 percent in the third quarter of 2005 to 31.8 percent in the fourth quarter of 2005 due to increased production from farm-in lands which incur gross overriding royalties and minor upward adjustments in the British Columbia royalty rates of certain properties. The 22 percent increase in the fourth quarter of 2005 royalty rate over the fourth quarter of 2004 rate of 26.0 percent, is a result of the elimination of Alberta volumes in the first quarter of 2005 which incurred lower royalty rates, the incurrence of gross overriding royalties on certain farm-in lands in northeast British Columbia, and higher natural gas prices.

Operating Expenses

Operating expenses for the fourth quarter of 2005 increased 14 percent to $1.9 million over the prior quarter of $1.7 million. On a boe basis, operating expenses in the fourth quarter were $4.48 compared to $5.58 recorded in the third quarter, a decrease of 20 percent. Operating expenses during the fourth quarter of 2004 were $6.33 per boe. The reduction in operating costs per boe is a result of ongoing operating efficiencies and the ability to spread certain fixed operating costs over increased production volumes. The decrease from the fourth quarter of 2004 is due to increased operating efficiencies and the sale of the Alberta properties in early 2005, which incurred higher operating expenses.

Transportation Expenses

Transportation expenses for the fourth quarter of 2005 were $1.4 million ($3.37 per boe), consistent with the prior quarter expense of $1.1 million ($3.71 per boe). Transportation expenses in the fourth quarter of 2004 of $0.3 million, resulted in $2.48 per boe which reflected the lower transportation rates incurred on the Alberta production. The Alberta properties were sold in January 2005. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expenses

For the fourth quarter of 2005, G&A expenses were $0.5 million ($1.20 per boe) compared to $0.3 million ($0.84 per boe) recorded in the prior quarter. Fourth quarter G&A expense was comprised of $0.4 million in direct G&A expenses, $0.6 million in technical service fees from Progress under the Technical Services Agreement (see Relationship with Progress) less $0.4 million in recoveries and $0.1 million in capitalized G&A expenses. During the prior quarter, G&A expenses were $0.3 million ($1.33 per boe) comprised of $0.2 million in G&A expenses, $0.6 million in technical service fees from Progress less $0.4 million in recoveries and $0.2 million in capitalized G&A expenses. The increase in G&A expenses in the fourth quarter of 2005 over the prior quarter is largely due to increased technical service fees from Progress. The Company recorded G&A expense of $0.2 million ($1.90 per boe) in the fourth quarter of 2004. The increase in G&A expenses over the fourth quarter of 2004 is a result of increases

in the technical service fees from Progress which is calculated based on the proportionate share of production and capital expenditures between the two entities.

Depletion, Depreciation and Accretion

For the fourth quarter of 2005, DD&A expenses increased 43 percent to $4.1 million from the $2.8 million recorded in the third quarter. On a boe basis, DD&A expenses remained consistent with the prior quarter, increasing from $9.62 in the third quarter to $9.68 in the fourth quarter. For the fourth quarter of 2004, the Company recorded a DD&A expenses per boe rate of $10.18 which reflected 2004 year end reserve adjustments including an increase to future development capital related to undeveloped reserves.

Income taxes

Future income taxes were $4.6 million for the fourth quarter of 2005 compared to $2.5 million for the prior quarter and $0.6 million in the fourth quarter of 2004. The increase in future taxes from the prior quarter and the fourth quarter of 2004 is due to increased earnings over both periods.

Net Earnings and Funds Generated From Operations

Net earnings for the fourth quarter of 2005 increased 117 percent to $7.8 million ($0.24 per basic share, $0.20 per diluted share) from $3.6 million ($0.11 per basic share, $0.09 per diluted share) recorded in the prior quarter. Net earnings in the fourth quarter of 2005 increased 638 percent over the $1.0 million ($0.04 per basic share, $0.03 per diluted share) recorded in the fourth quarter of 2004.

The Company recorded $16.5 million ($0.50 per basic share, $0.41 per diluted share) in funds generated from operations in the fourth quarter, an 85 percent increase over the $9.0 million ($0.29 per basic share, $0.23 per diluted share) recorded in the prior quarter, and a 474 percent increase from the $2.9 million ($0.11 per basic share, $0.09 per diluted share) recorded in the fourth quarter of 2004. The increase in net earnings and funds generated from operations over the third quarter and over the fourth quarter of 2004 is due to a higher production and natural gas prices.

Capital Investment

Capital investment during the fourth quarter of $28.7 million was consistent with the prior quarter of $27.8 million and the fourth quarter of 2004 of $27.6 million. The fourth quarter of 2005 included $17.6 million in drilling and completions, $5.0 million in land acquisitions, $3.4 million in geological and geophysical activities, and $2.7 million in facilities.

RELATIONSHIP WITH PROGRESS

Technical Services Agreement

In conjunction with the Plan of Arrangement, ProEx and Progress entered into a Technical Services Agreement which provides for the shared services required to manage ProEx's activities and govern the allocation of G&A expenses between the entities. Under the Technical Services Agreement, ProEx is charged a technical services fee by Progress, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. The technical services fee for 2005 was $2.8 million (2004 - $0.6 million).

Protocol Arrangement

In conjunction with the Plan of Arrangement, ProEx assumed the interests in certain of Progress' producing assets and undeveloped land. Through this transaction both ProEx and Progress have joint interests in certain properties and undeveloped lands. The inter-corporate relationship on the governance of these lands is dictated by standard industry agreements. To ensure good governance practices, the Company has a Protocol Arrangement that specifies how the companies will manage the joint lands in specifically identified areas of interest. The arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. The arrangement also outlines the practices to be followed in the event either party enters into areas outside of the identified areas of interest.

Farm-In Agreement

Under the Plan of Arrangement, ProEx received an option to farm-in on 25,000 net acres of Progress exploratory lands, retained by Progress, on standard industry terms. As at December 31, 2005, ProEx has drilled nine earning wells, five additional wells on earned lands and retains an option on 20,095 net acres of Progress lands. This agreement is scheduled to expire on July 2, 2006.

Independent Committee of the Board of Directors

Both ProEx and Progress have created independent committees of the Board of Directors to deal with technical services issues. The Committees' mandate includes the following:

- To consider any issues related to the Technical Services Agreement between Progress and ProEx that they consider appropriate or that are directed to the Committee by Management.
- To meet with the Technical Services Committee or similar committee of Progress when appropriate.
- To advise the Board of Directors of decisions by the Technical Services Committee of interpretations, amendments or issues in dispute.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the financial statements in accordance with Canadian GAAP requires management to make judgments and estimates that affect the financial results of the Company. ProEx's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. A summary of significant accounting policies are presented in Note 1 to the financial statements. The critical estimates are discussed below:

Petroleum and Natural Gas Reserves

All of ProEx's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"). The evaluation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, commodity prices and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and changes in costs and commodity prices.

Depletion Expense

The Company uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development capital is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development capital have a direct impact on depletion expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion expense.

Asset Retirement Obligations

The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by ProEx is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

CHANGE IN ACCOUNTING POLICIES

During 2005, the following amended guideline was issued:

Internal Control Reporting

Multilateral Instrument 52-111 Reporting on Internal Control over Financial Reporting and 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings set out the key provisions relating to the evaluation, assessment and certification of the internal controls over financial reporting ("ICOFR") by management and the audit by the external auditors of managements' assessment of ICOFR. The objective of the new rules is to improve the quality and reliability of financial reporting by requiring issuers to evaluate the controls over the preparation of financial statements. The new rules are phased in with final implementation of the evaluation of the effectiveness by management and attestation by the external auditors of ICOFR for financial years ended after June 30, 2008. In accordance with the Technical Services Agreement with Progress, ProEx relies upon the systems and processes utilized by Progress and has developed a plan in conjunction with Progress in order to be in full compliance by the final phase in date.

RISK ASSESSMENT

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following reviews the general and specific risks.

Exploration, Development & Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. ProEx's long-term commercial success depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves it may have at any particular time and the production there from will decline over time as such existing reserves are exploited. A future increase in ProEx's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, ProEx may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by ProEx.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include: delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas release and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although ProEx maintains liability insurance, when available, in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risk typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into production formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Finding Oil and gas exploration requires manpower and capital to generate and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves. ProEx attempts to minimize finding risk by ensuring that:

- The majority of prospects have multi-zone potential.
- Activity is focused in core regions where expertise and experience is greatest.
- Number of wells drilled is large enough to increase the probability of statistical success rates.
- Working interest are targeted at over 60 percent in new prospects.
- Geophysical techniques are utilized where appropriate.

Investment Risk Profile The Company's investment selection process is based on risk analysis to ensure capital expenditures balance the objectives of immediate cash flow growth (development activity) and future cash flow from the discovery or reserves (exploration). This careful prospect selection process can yield consistent and efficient results. The Company focuses its activity in two core regions, allowing it to leverage off its experience and knowledge in these areas further aiding efficiencies. The Company attempts to maintain a broad range of investment choices to limit the investment risk by continually investing a portion of its annual budget to future years. The Company attempts to use farm-outs to minimize risk on plays it considers higher risk.

Production Beyond exploration risk, there is the potential that the Company's oil and natural gas reserves may not be economically produced at prevailing prices. ProEx minimizes this risk by generating exploration prospects internally, targeting high quality projects and attempting to operate the associated project. Operational control allows the Company to control costs, timing, method and sales of production. Production risk is also minimized by concentrating exploration efforts in regions where facilities and infrastructure are ProEx owned, or the Company can control the future development of new facilities and infrastructure.

Reserve Estimates Economically recoverable oil and natural gas reserves (including natural gas liquids), estimated by the Company's independent engineering firm, GLJ Petroleum Consultants Ltd., and the future net cash flows there from are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected there from, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Competitive Industry Conditions

The western Canadian oil and natural gas industry has become a very competitive industry for oil and gas properties, undeveloped land, drillable prospects and oil and natural gas industry professionals. The Company was initially seeded with a large undeveloped land base that provided a quality inventory of exploration prospects and attempts to mitigate this future risk by developing its own exploration prospects, and through these efforts build a quality inventory of undeveloped lands and drillable prospects that can fuel future growth. The Company has a Technical Services Agreement with Progress that provides the Company with a quality group of industry professionals to enable it to execute its business plan.

Supply of Service and Production Equipment

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce these reserves in an economic and timely fashion. In periods of increased activity these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long term relationships with suppliers and contractors.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control. ProEx's ability to market its natural gas may depend upon our ability to acquire space on pipelines that delivery natural gas to commercial markets. We may also be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government and regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of our reserves. ProEx might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue causing a reduction in its oil and gas acquisition development and exploration activities. In addition, bank borrowings available to use are in part determined by our borrowing base, A sustained material decline in prices from historical average prices could reduce our borrowing base, therefore reducing the bank credit available to us which could require that a portion, or all, of our bank debt be repaid.

Demand for crude oil and natural gas produced by the Company exists within Canada and the US, however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is dictated predominately by demand for petrochemicals in North American and offshore markets. ProEx mitigates the risks as follows:

- Crude oil production is of a high quality and hence not subject to adverse quality differentials.
- Natural gas is connected to mature pipeline infrastructure that operates with minimal interruptions.
- Exploration efforts target high quality oil and liquids rich natural gas reserves.
- Exploration efforts are concentrated in regions where marketing expertise levels are highest.
- Financial instruments are used, where appropriate, to manage commodity price volatility.

Risk Management

From time to time, ProEx may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases. Similarly, from time to time, ProEx may enter into agreements to fix the exchange rate of Canadian to US dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

ProEx has a Risk Management Policy, the objective of which is to ensure cash flow is sufficient to fund the capital program and cover debt payments by reducing the exposure to commodity prices, foreign exchange and interest rate volatility. These objectives may be achieved through the use of financial instruments or through fixed price contracts for the delivery of physical volumes. The program has established targets and guidelines as approved by the Board of Directors from time to time. Effective controls and procedures are in place to ensure that the mandate is followed. As at the date of this report, the Company has not entered into any derivative financial instruments.

Technology Risks

The Company relies on information technology systems owned and managed by Progress in accordance with the Technical Services Agreement to manage its day to day operations and perform reporting obligations including the preparation of financial statements, reporting to joint partners and various governments in relation to payment of royalties and taxes.

Technical Services Agreement

The Company has a Technical Services Agreement with Progress, whereby Progress provides services required to manage ProEx's activities including management, development, exploitation, operations, administrative marketing activities and information technology systems. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or at some other date as may be mutually agreed.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. ProEx's operations may require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at it projects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". ProEx's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject it to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed in Alberta's Bill 32: Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity produced by the Company's operations and facilities. The direct or indirect costs of these regulations may adversely affect the Company's business.

Environmental and Safety Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provisional and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge.

There are potential risks to the environment inherent in the business activities of the Company. ProEx has developed and implemented policies and procedures to mitigate environmental, health and safety (EH&S) risks. These policies and procedures include the corporate EH&S policy, emergency response plans, the corporate EH&S Management System, and other policies and procedures. These policies and procedures are designed to protect and maintain the environment, and public and employer safety, with respect to all corporate operations on behalf of shareholders, employees and the public at large. The Company mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations. The Company has estimated asset retirement obligations of $1.4 million as at December 31, 2005. The Company recognizes period-to-period changes in the liability of the asset retirement obligation resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

Financial and Liquidity Risks – Additional Funding Requirements

The funds generated from operations from the Company's reserves may not be sufficient to fund its ongoing activities at all times. From time to time, ProEx may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. ProEx relies on various sources of funding to support its growing capital expenditure program, including:

- Internally generated cash flow provides the minimum level of funding on which the Company's annual capital expenditures program is based.
- Debt may be utilized to expand capital programs when deemed appropriate.
- New equity, if available and on favorable terms, will be utilized to expand exploration programs.

Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate operations. If the revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will effect its ability to expend the necessary capital to replace its reserves or to maintain its production. If funds generated from operations is not sufficient to satisfy capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable. Neither its articles nor by-laws limit the amount of indebtedness that the Company may incur. The level of indebtedness from time to time, could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. In addition, cash flow is influenced by factors, which the Company cannot control,

such as commodity prices, the US/Cdn exchange rate, interest rates and changes to existing government regulations and tax policies. Should circumstances affect cash flow in a detrimental way, ProEx would respond by increasing debt to within the Company's self-imposed debt guideline and/or reducing capital expenditures.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in its becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although prior to drilling ProEx will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, ProEx may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds generated from operations. The occurrence of a significant event that ProEx is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects.

Conflicts of Interest

Certain directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Most notably, all of our officers are also officers of Progress. The potential conflicts of interests between ProEx and Progress are attempted to be mitigated by independent committees of each of the respective entities boards of directors being on committees that oversee the application of the Technical Services Agreement. Conflicts, if any, will be subject to the procedures and remedies of the Alberta Business Corporations Act.

Reliance on Key Personnel

ProEx's success depends in large measure on certain key personnel, including those of Progress. The loss of the services of such key personnel could have a material adverse affect on ProEx. We do not have key person insurance in effect for management. The contributions of these individuals to ProEx's immediate operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management.

ADDITIONAL INFORMATION

Additional information relating to the Company, is filed on SEDAR and can be viewed at www.sedar.com. Also information can also be obtained by contacting the Company at ProEx Energy Ltd. 1400, 440 – 2nd Avenue S.W., Calgary, Alberta, Canada T2P 5E9 or by e-mail at ir@proexenergy.com. Information is also accessible on the Company's web site at www.proexenergy.com.

Reserves

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVE DATA AND OTHER INFORMATION (NI 51-101F3)

Management of ProEx Energy Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecasted prices and costs; and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and
(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserve data. The report of the independent qualified reserve evaluator is presented below.

The Reserves Committee of the Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filings with securities regulatory authorities of the reserves data and other oil and gas information;
(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

D. D. Johnson

President & Chief Executive Officer

Director & Chairman Reserves Committee

Vice President Production

Director & Member of the Reserve Committee

REPORT ON RESERVE DATA (NI 51-101 F2)

To the Board of Directors of ProEx Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserve data as at December 31, 2005. The reserve data consist of the following:
   - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

     (ii) the related estimated future net revenue; and
   - (b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and

     (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society)
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecasted prices and costs and calculated using a discount rate of 10 percent, included in the reserve data of the Company evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present value of Future Net Revenue (before income taxes, 10% discount rate) ($M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	February 9, 2006	Canada		214,326		214,326

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, February 15, 2006

Myron Hladyshevsky
Vice-President, GLJ Consultants Ltd.

Myron Hladyshevsky

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION (NI 51-101F1)

The statement of reserves data and other oil and natural gas information set forth below is dated effective December 31, 2005 and the preparation date is February 28, 2006.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserve Data") is based upon an evaluation by GLJ Petroleum Consultants ("GLJ") with an effective date of December 31, 2005 and dated February 15, 2006 ("GLJ Report"). The Reserves Data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. We engaged GLJ to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of our reserves are in Canada and, specifically, in the province of British Columbia.

Cautionary Statements

Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

All evaluations and reviews of future net cash flow are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to the risks involved, see "Risk Factors". Columns may not add due to rounding.

Summary of Reserves (forecast prices)

	2005	2004
Proved		
Light and medium oil *(mbbls)*	500	478
Gas *(mmcf)*	64,436	26,467
NGL *(mbbls)*	532	202
BOE *(mboe)*	11,771	5,091
Proved plus probable		
Light and medium oil *(mbbls)*	651	655
Gas *(mmcf)*	82,141	35,366
NGL *(mbbls)*	683	278
BOE *(mboe)*	15,024	6,827

Summary of Oil and Gas Reserves and Net present Values of Future Net Revenue

As of December 31, 2005

Constant Prices and Costs

	Reserves							
Reserve Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Boe	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbl)	*(mbbl)*	*(mmcf)*	*(mmcf)*	*(mbbl)*	*(mbbl)*	*(mboe)*	*(mboe)*
Proved								
Developed Producing	383	334	46,022	33,858	374	290	8,427	6,268
Developed Non-Producing	98	87	7,670	5,938	74	57	1,451	1,134
Undeveloped	24	20	10,901	8,234	86	68	1,927	1,460
Total Proved	506	441	64,594	48,030	534	415	11,805	8,862
Probable	150	133	17,750	13,299	152	118	3,261	2,468
Total Proved Plus Probable	656	574	82,344	61,329	686	534	15,066	11,330

Reserve Category	Net Present Value of Future Net Revenue: Before Income Taxes Discounted at (%/year) 0	5	10	15	20	After Income Taxes Discounted at (%/year) 0	5	10	15	20
	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)
Proved										
Developed Producing	273.3	195.2	154.8	130.0	113.3	219.0	161.2	130.6	111.5	98.4
Developed Non-Producing	45.5	33.3	26.1	21.4	18.1	29.9	21.9	17.2	14.2	12.1
Undeveloped	57.4	36.4	26.0	19.8	15.8	38.0	23.9	16.8	12.6	9.9
Total Proved	376.1	264.9	206.8	171.2	147.2	286.9	207.0	164.6	138.3	120.3
Total Probable	106.2	52.9	33.3	23.9	18.5	70.2	35.0	22.0	15.7	12.1
Total Proved Plus Probable	482.3	317.9	240.1	195.1	165.6	357.1	242.0	186.6	154.0	132.4

Total Future Net Revenue (Undiscounted)
As of December 31, 2005

Constant Prices and Costs

Reserve Category	Revenue	Royalties, Mineral Tax, ARTC (1)	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)	($MM)
Proved	636.4	146.9	98.9	12.9	1.6	376.1	89.2	286.9
Proved plus Probable	812.1	186.5	127.1	14.5	1.7	482.3	125.2	357.1

(1) Mineral tax amounts to $0 in the proved reserves case and $0 in the proved plus probable case. ARTC amounts to $0 in the proved reserves case and $0 in the proved plus probable case.

Future Net Revenue by Production Group
As of December 31, 2005

Constant Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		($MM)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	15.4
	Natural Gas (including by-products but excluding solution gas from oil wells	191.4
	Other revenue/costs	
	Total	206.8

** Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups*

Summary of Pricing Assumptions
As of December 31, 2005

Constant Prices and Costs

This summary table identifies benchmark reference pricing that applies to the Company.

Year	WTI Cushing Oklahoma	Edmonton Par Price 400 API	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus	Inflation Rates	Exchange Rate
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/Year)	($US/$Cdn)
Historical							
2001	25.97	39.40	31.85	31.17	42.48	2.6	0.6448
2002	26.08	40.33	21.39	27.08	40.73	2.2	0.6376
2003	31.07	43.66	32.14	34.36	44.23	2.8	0.7213
2004	41.38	52.96	34.70	39.97	54.07	1.8	0.7680
2005	56.58	69.11	43.04	51.80	69.47	2.2	0.8250
Forecast							
2006+	61.04	68.27	43.69	50.52	71.67	0	0.8577

	Natural Gas			
Year	US Gulf Coast @ Henry Hub	Midwest @ Chicago	AECO Gas Price	Sumas Spot Gas Price
	($US/MMBtu)	($US/MMBtu)	($Cdn/MMBtu)	($US/MMBtu)
Historical				
2001	4.05	4.17	6.21	4.56
2002	3.36	3.30	4.04	2.68
2003	5.50	5.60	6.66	4.66
2004	6.19	6.13	6.88	5.26
2005	8.97	8.24	8.58	7.13
Forecast				
2006+	11.23	9.06	9.71	8.25

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue
As of December 31, 2005

Forecasted Prices and Costs

Reserve Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Boe	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbl)	(Mbbl)	(Mmcf)	(Mmcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)
Proved								
Developed producing	378	330	45,913	33,769	372	289	8,402	6,247
Developed non-producing	97	86	7,621	5,895	73	56	1,441	1,125
Undeveloped	24	20	10,901	8,234	86	68	1,927	1,460
Total proved	500	435	64,436	47,899	532	414	11,771	8,832
Probable	151	134	17,705	13,259	151	118	3,254	2,462
Total proved plus probable	651	569	82,141	61,158	683	532	15,024	11,294

Net Present Value of Future Net Revenue

Reserve Category	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
	0	5	10	15	20	0	5	10	15	20
	($MM)	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*
Proved										
Developed producing	239.7	174.3	141.7	121.9	108.5	196.8	147.6	122.4	106.8	96.0
Developed non-producing	37.1	27.9	22.5	18.9	16.4	24.4	18.2	14.5	12.1	10.4
Undeveloped	48.4	30.6	22.0	17.0	13.8	31.9	19.8	13.9	10.5	8.2
Total proved	325.2	232.8	186.1	157.9	138.7	253.0	185.6	150.8	129.3	114.6
Probable	97.3	45.6	28.2	20.3	15.9	64.3	30.0	18.5	13.2	10.3
Total proved plus probable	422.5	278.4	214.3	178.2	154.6	317.3	215.6	169.3	142.6	124.9

Total Future Net Revenue (Undiscounted)

As of December 31, 2005

Forecasted Prices and Costs

Reserve Category	Revenue	Royalties, Mineral Tax, ARTC [1]	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	($MM)	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*	*($MM)*
Proved	595.0	133.3	121.0	13.1	2.4	325.2	72.2	253.0
Proved Plus Probable	774.5	170.7	163.8	14.7	2.8	422.5	105.2	317.3

(2) Mineral tax amounts to $0 in the proved reserves case and $0 in the proved plus probable case. ARTC amounts to $0 in the proved reserves case and $0 in the proved plus probable case.

Future Net Revenue by Production Group

As of December 31, 2005

Forecasted Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		($MM)
Proved	Light and Medium Crude Oil *(including solution gas and other by-products)*	13.2
	Natural Gas (including by-products but excluding solution gas from oil wells)	172.9
	Total	186.1
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	14.8
	Natural Gas (including by-products but excluding solution gas from oil wells)	199.6
	Total	214.3

**Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups*

Summary of Pricing and Inflation Rate Assumptions
As of December 31, 2005

Forecast Prices and Costs

This summary table identifies benchmark reference pricing that apply to the Company. The oil, gas, NGL reference prices, inflation rates and exchange rates used in the forecasted price evaluation were prepared by GLJ the Company's independent qualified reserves evaluator and are as follows:

	Oil		Natural Gas Liquids				
Year	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus	Inflation Rates	Exchange Rate
	(US$/bbl)	*(Cdn$/bbl)*	*(Cdn$/bbl)*	*(Cdn$/bbl)*	*(Cdn$/bbl)*	*(%/Year)*	*(US$/Cdn$)*
Historical							
2001	25.97	39.40	31.85	31.17	42.48	2.6	0.646
2002	26.08	40.33	21.39	27.08	40.73	2.2	0.637
2003	31.07	43.66	32.14	34.36	44.23	2.8	0.721
2004	41.38	52.96	34.70	39.97	54.07	1.8	0.768
2005	56.60	69.11	42.55	51.41	69.45	2.2	0.825
Forecast							
2006	57.00	66.25	42.50	49.00	67.00	2.0	0.850
2007	55.00	64.00	41.00	47.25	65.25	2.0	0.850
2008	51.00	59.25	38.00	43.75	60.50	2.0	0.850
2009	48.00	55.75	35.75	41.25	56.75	2.0	0.850
2010	46.50	54.00	34.50	40.00	55.00	2.0	0.850
2011	45.00	52.25	33.50	38.75	53.25	2.0	0.850
2012	45.00	52.25	33.50	38.75	53.25	2.0	0.850
2013	46.00	53.25	34.00	39.50	54.25	2.0	0.850
2014	46.75	54.25	34.75	40.25	55.25	2.0	0.850
2015	47.75	55.50	35.50	41.00	56.50	2.0	0.850
2016	48.75	56.50	36.25	41.75	57.75	2.0	0.850
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.850

Year	Natural Gas				
	Us Gulf Coast @ Henry Hub	Midwest @ Chicago	AECO Gas Price	Sumas Spot gas Price	Saskatchewan Plant Gate Spot
	($US/MMBtu)	*($US/MMBtu)*	*($Cdn/MMBtu)*	*($US/MMBtu)*	*($/MMBtu)*
Historical					
2001	4.05	4.17	6.21	4.56	6.13
2002	3.36	3.30	4.04	2.68	4.08
2003	5.50	5.60	6.66	4.66	6.68
2004	6.19	6.13	6.88	5.26	6.78
2005	8.97	8.24	8.58	7.13	8.36
Forecast					
2006	10.50	10.30	10.60	9.40	10.50
2007	8.75	8.90	9.25	8.15	9.15
2008	7.50	7.65	8.00	7.00	7.90
2009	7.00	7.15	7.50	6.55	7.40
2010	6.75	6.90	7.20	6.30	7.10
2011	6.50	6.60	6.90	6.05	6.80
2012	6.50	6.65	6.90	6.05	6.80
2013	6.65	6.80	7.05	6.20	6.95
2014	6.75	6.90	7.20	6.30	7.10
2015	6.90	7.05	7.40	6.45	7.30
2016	7.05	7.20	7.55	6.60	7.45
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Reconciliation of Company Net[(2)] Reserves by Principal Product Type

Forecast Prices and Costs

		Light and Medium Crude	Natural Gas	Natural Gas Liquids	BOE
		(mbbl)	(bcf)	(mbbl)	(mboe)
Total Proved	Opening balance	417	19.06	153	3,746
	Exploration discoveries	42	2.45	25	-
	Drilling extensions	27	22.67	181	3,987
	Infill Drilling	-	-	-	476
	Improved recovery	38	8.39	61	1,499
	Technical revisions	29	1.15	14	234
	Economic factors	3	(0.01)	-	2
	Acquisitions	-	-	-	-
	Dispositions	(34)	(1.18)	(6)	(238)
	Production	(88)	(4.63)	(14)	(874)
	Closing balance	435	47.90	414	8,832
Probable	Opening balance	155	6.58	59	1,310
	Exploration discoveries	43	0.57	7	145
	Drilling extensions	7	5.56	44	977
	Infill Drilling	-	-	-	-
	Improved recovery	(8)	2.20	16	374
	Technical revisions	(56)	(1.18)	(5)	(259)
	Economic factors	3	(0.01)	-	2
	Acquisitions	- -		-	-
	Dispositions	(9)	(0.46)	(3)	(87)
	Production	-	-	-	-
	Closing balance	134	13.26	118	2,462
Proved Plus Probable	Opening balance	572	25.63	212	5,056
	Exploration discoveries	85	3.02	32	621
	Drilling extensions	34	28.23	225	4,963
	Infill Drilling	-	-	-	-
	Improved recovery	30	10.59	77	1,873
	Technical revisions	(27)	(0.03)	8	(24)
	Economic factors	6	(0.01)	-	4
	Acquisitions	-	-	-	-
	Dispositions	(43)	(1.6)	(9)	(325)
	Production	(88)	(4.63)	(14)	(874)
	Closing balance	569	61.16	532	11,294

Reconciliation of Company Interest Reserves by Principal Product Type

Forecast Prices and Costs

		Light and Medium Crude	Natural Gas	Natural Gas Liquids	BOE
		(mbbl)	(bcf)	(mbbl)	(mboe)
Proved Producing	Opening balance	297.4	14.86	110.7	2,884.5
	Exploration discoveries	-	4.48	31.9	779.2
	Drilling extensions	43.4	25.33	179.0	4,443.8
	Improved recovery	49.9	5.65	53.6	1,044.9
	Technical revisions	125.1	2.84	32.4	630.1
	Economic factors	-	-	-	-
	Acquisitions	-	-	-	-
	Dispositions	(37.6)	(1.07)	(7.0)	(223.4)
	Production	(100.1)	(6.16)	(28.1)	(1,154.1)
	Closing balance	378.2	45.93	372.5	8,405.1
Total Proved	Opening balance	478.3	26.55	202.8	5,105.4
	Exploration discoveries	45.7	3.12	31.1	596.3
	Drilling extensions	34.4	30.24	230.9	5,304.8
	Infill Drilling	49.9	11.13	76.7	1,982.3
	Improved recovery	-	-	-	-
	Technical revisions	29.4	1.07	28.3	236.8
	Economic factors	-	-	-	-
	Acquisitions	-	-	-	-
	Dispositions	(37.6)	(1.50)	(9.9)	(298.1)
	Production	(100.0)	(6.16)	(28.1)	(1,154.1)
	Closing balance	500.1	64.45	531.9	11,773.4
Probable	Opening balance	176.9	8.91	76.4	1,739.0
	Exploration discoveries	46.5	0.75	9.3	180.6
	Drilling extensions	8.4	7.41	55.8	1,299.5
	Infill Drilling	(10.5)	2.84	19.7	481.9
	Improved recovery	-	-	-	-
	Technical revisions	(59.9)	(1.64)	(6.0)	(339.7)
	Economic factors	-	-	-	-
	Acquisitions	-	-	-	-
	Dispositions	(9.9)	(0.56)	(3.6)	(107.1)
	Production	-	-	-	-
	Closing balance	151.5	17.71	151.4	3,254.2
Proved Plus Probable	Opening balance	655.2	35.46	279.2	6,844.4
	Exploration discoveries	92.2	3.87	40.4	776.9
	Drilling extensions	42.8	37.65	286.7	6,604.3
	Infill Drilling	39.4	13.97	96.4	2,464.2
	Improved recovery	-	-	-	-
	Technical revisions	(30.5)	(0.57)	22.3	(102.9)
	Economic factors	-	-	-	-
	Acquisitions	-	-	-	-
	Dispositions	(47.5)	(2.07)	(13.5)	(405.2)
	Production	(100.1)	(6.16)	(28.1)	(1,154.1)
	Closing balance	651.6	82.16	683.3	15,027.6

Closing balances may be slightly higher than reported Company gross reserves due to the inclusion of recoverable royalties.

2005 Reconciliation of Changes in Net Present Values of Future Net Revenue Discounted at 10% per Year

Proved Reserves

Constant Prices and Costs

	2005	
Period and Factor	*After Tax ($M)*	*Before Tax ($M)*
Estimated Future Net Revenue at Beginning of Year	56,717	65,557
Sales and Transfers of Oil and Gas Produced , Net of Production Costs and Royalties (1)	(40,350)	(40,350)
Net Change in Prices, Production Costs and Royalties Related to Future Production (2)	33,305	33,305
Changes in Previously Estimated Development Costs Incurred During the Period (3)	93,361	93,361
Changes in Estimated Future Development Costs (4)	(100,728)	(100,728)
Extensions and Improved Recovery (5)	123,563	123,563
Discoveries (5)	10,027	10,027
Acquisition of Reserves (5)	-	-
Disposition of Reserves (5)	(5,962)	(5,962)
Net Change Resulting from revisions in Quantity Estimates	944	944
Accretion of Discount (6)	6,556	6,556
Net Change in Income Taxes (7)	(33,333)	-
All Other Changes	20,525	20,525
Estimated Future Net Revenue at End of Year	164,626	206,799

(1) Company actual before income taxes, excluding G & A
(2) The impact of changes in prices and other economic factors on future net revenue
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves
(4) The change in forecast development costs for the properties evaluated at the beginning of the period.
(5) End of period net present value of the related reserves.
(6) Estimated as 10% of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

Additional Information Relating to Reserve Data

Undeveloped Reserves

Proved Undeveloped Reserves

Nearly all of the Company's proved undeveloped reserves fall within the following categories:

- Wells budgeted and scheduled to be drilled in 2006
- Gas caps that will be blown down once the oil has been depleted
- Secondary zones that will be brought on production once the primary zone has been depleted

The Company does not carry proved undeveloped reserves for long periods of time unless there is a good reason (such as the above) for not putting these reserves on production in the short term. In fact, where there is sufficient economic justification, the Company will often take steps to accelerate production from gas caps and secondary zones. These steps involve early gas cap blowdown when it does not significantly impact oil recovery and dually completing or twinning wells for secondary zones.

Probable Undeveloped Reserves

Sixty percent of the Company's probable reserves are attributed to more optimistic recoveries from producing wells. The remaining probable reserves for the most part are attributed to step-out drilling locations, re-completions, and tie-ins that are anticipated to proceed in the near-term but do not meet the required confidence factor to be booked as proved. The comments above regarding the Company's efforts to put proved undeveloped reserves onstream also apply to probables.

Significant Factors or Uncertainties

Estimates of economically recoverable oil and natural gas reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

The Company's independent engineering firm, GLJ, uses a deterministic approach in the estimation of reserves. Reserves are assessed using a discrete value for each parameter in the calculation of reserves, such that the resultant reserve value is consistent with the certainty level associated with the reserve classification. In accordance with NI 51-101, the following definitions are followed by GLJ in their analysis:

- Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Future Development Costs

($M)	Forecast Prices and Costs		Constant Prices and Costs	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2006	10,496	11,847	10,496	11,847
2007	1,909	2,041	1,871	2,001
2008	31	31	30	30
2009	41	41	38	39
2010	44	44	41	41
Remainder	550	656	466	506
Total	13,071	14,660	12,942	14,464
10% disc.	11,986	13,340	11,914	13,262

In all years of the economic forecasts, the net revenues from the Company's reserves are well in excess of the estimated future development costs. Therefore the Company can meet the funding requirements for future development entirely out of its cash flow and no other source of funding is required to develop the proved or the proved plus probable reserves.

Other Oil and Gas Information

ProEx Energy operates exclusively on the plains and foothills regions of northeast British Columbia. The Company together with Progress Energy Trust is the operator of the majority of its properties and has contiguous undeveloped acreage in its core areas. These two regions provide multi-zone opportunities and year round access with existing gathering and processing facilities. The Company's entire 2005 capital program was directed within these regions.

British Columbia

ProEx has developed a strong substantial land and production base in two regions of northeast British Columbia, the Fort St John Plains and the Greater Gundy shallow foothills region. ProEx is an active driller and land acquirer in these areas and has become comfortably fluent in its understanding of government, environment and First Nations issues, barriers to entry of many of our competitors. The Company relies on a gas processing infrastructure operated by Duke Energy that enables producers in this province to avoid major facility construction in exchange for regulated gathering, processing and transmission fees. The Company processes a substantial percentage of its natural gas through the Duke operated McMahon Gas Plant located south of the town of Fort St. John, British Columbia.

Fort St. John Plains

ProEx plans to participate with Progress Energy Trust, the operator, in a number of lower risk drilling projects in the Fort St. John block. This all season access area contains a significant portfolio of potential reservoir targets containing light oil and natural gas in depths less than 2,000 meters. Drilling activities were conducted in the Two Rivers Siphon oil project, Current Halfway-Gething gas project and at Osprey Bluesky-Gething gas project during 2005. This area currently produces approximately 900 boepd net to ProEx and contains 26,000 undeveloped acres of land. ProEx generally holds a 20 percent of the working interest in this area.

The Fort St. John plains area is located in close proximity to the city of Fort St. John, British Columbia on the northern flank of the Peace River. The Fort St. John area produces light oil and natural gas from a predictable sequence of porous Cretaceous and Triassic aged sandstones and carbonates. Up to ten separate and distinct reservoirs can be encountered in a typical 1,200 meter depth well in the Fort St. John plains exploration area. ProEx controls approximately 26,000 acres of undeveloped land in the area and will have an active drilling program in the plains area participating in approximately 5 to 7 gross wells.

Stoddart Belloy project In 2005, ProEx participated in the drilling of a 2000 m depth exploration well testing a seismic feature expressed at the Permian aged Belloy sandstone level that resulted in a significant new gas discovery. ProEx expects to continue this drill effort in 2006 with four to five gross tests in the area pending the interpretation of new seismic data.

Beaverdam – Current The Cretaceous-Triassic reservoirs in this 1200m depth to target area are well expressed with high definition seismic data. While the pool sizes are somewhat limited drill events payout quickly and profits are redeployed into longer life projects elsewhere in ProEx's drill portfolio. The Company intends on drilling one to two gross wells here in 2006.

Northeast British Columbia Shallow Foothills

Approximately 100 kilometers northwest of the city of Fort St. John the British Columbia is the northeast British Columbia shallow foothills area to the west of the 1 Tcf Beg gas field which has become a key area of focus for the Company. The main foothills targets are the same as those found on the Fort St. John block (Cretaceous and Triassic sands) but are thicker and fractured on a series of parallel anticlines giving rise to larger accumulations with high flow rates. The primary target Halfway zone is a tight but thick gas charged reservoir in the foothills, where folded and fractured by mountain building compressive forces from the west, the Halfway reservoir, together with other natural gas zones stacked above, can produce very commercial long life gas flow rates. ProEx has been able to successfully image and identify these features using modern 3-D seismic data. The main exploratory areas in the ProEx portion of the foothills are at Gundy Creek, West Beg, Julienne and Sasquatch.

Gundy Creek In 2005 ProEx continued a modest drilling program on two anticlines in the Gundy area and brought the Gundy compressor up to production at 10 mmcf per day. For 2006, the Gundy drilling program will focus on fully utilizing the current facility.

West Beg Three Halfway anticlines were identified from the 3-D program shot in the winter of 2005 at West Beg. Eleven wells were drilled on two of the anticlines in the year bringing area production up from zero to 12 mmcf per day at year end. For 2006 ProEx will drill wells on four other identified independent features at West beg, each of which could spawn development programs if successful.

Sasquatch In addition to the north of West Beg at Sasquatch, ProEx is undertaking a 280 square kilometer 3-D seismic program in the effort to identify existing pool extensions and new subsurface features.

Julienne This is a new exploration area for ProEx some 25 km to the west of established production at Town. ProEx intends on drilling at least five exploration wells in this area in 2006 on newly acquired 3-D. The Julienne block has mapped potential in the Gething and Halfway sands and Debolt carbonates.

ProEx controls approximately 136,000 acres of land and will have access to over 865 square kilometers of 3-D seismic in the Town, Gundy, Julienne, and Sasquatch areas of the foothills. The Company intends to drill over 25 wells in the foothills during 2006. ProEx holds an 80 percent working interest in this area.

Alberta

Halkirk The east central Alberta natural gas and light oil project area is located approximately 100 kilometers east of the City of Red Deer. On January 27, 2005 the Company disposed of its interest in this area.

Oil and Natural Gas Wells

The following table sets forth the Company's gross and net interest in oil and natural gas wells which are producing and the number of non-producing wells and service wells as at December 31, 2005.

	Producing Wells				Non-Producing Wells				Service Wells	
	Oil		Gas		Oil		Gas			
	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]
British Columbia	41	6.5	85	35	27	3.2	99	29	5	0.7

Properties with No Attributed Reserves

The following table sets forth the Company's undeveloped land holdings and option lands as at December 31, 2005.

	Owned Undeveloped Land		Option Lands [1]
	Gross	Net	Total
	(acres)	*(acres)*	*(acres)*
British Columbia	321,460	160,869	46,567

(1) Due to the nature of the land deals wherein the farmors have the option to elect to remain in an overriding royalty position rather than convert to a working interest position, all option lands are quoted in total acres under option before any possible conversion election.

As part of the Company's land capture strategy it will commit to industry partners to drill wells and or shoot seismic in order to earn positions in contiguous land blocks in core areas. ProEx has committed in 2006 to drill four wells estimated to cost approximately $4 million, earning lands from area competitors in the shallow foothills regions of northeast British Columbia. In addition, during the first quarter of 2006, ProEx will be undertaking a $7 million program at Sasquatch area of northeast British Columbia which will include a seismic program designed to image the northern extension of the existing producing West Beg pool. During 2006, approximately 800 net acres of the Company's undeveloped land is expiring.

Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities through its previous experience, where available, or by estimating such costs. The Company expects to incur abandonment and reclamation costs on 257 gross wells (74.2 net wells) including currently producing, non-producing wells and service wells as detailed as follows:

	Proved NPV 0% *($M)*	Proved NPV 10% *($M)*
Associated with wells that have assigned reserves	1,605	406
Reclamation costs associated with wells that have assigned reserves [1]	1,376	348
Associated with non-producing, shut-in and wells that have no reserves assigned [1]	1,974	499
Total abandonment and reclamation cost provision	4,955	1,253
Portion forecast to be paid during the next three years	107	

(1) The Company has taken abandonment costs from the GLJ report (proved forecast) for wells that have reserves. Internal estimates were used for abandonment costs for wells that do not have reserves and surface reclamation costs for all wells. The internal estimates have not been deducted in estimating the future net revenue. The Company expects to incur abandonment and reclamation costs on 67.3 net wells including currently producing, non-producing and service wells as detailed previously.

Tax Horizon

The incomes taxes deducted in the calculation of future net revenue above assumes a blow down scenario whereby the Company produces out its existing reserves.

The Company forecasts its tax horizon, assuming current commodity prices, and a continuing business model whereby it reinvests capital at historic capital efficiencies and incurs general and administrative costs and interest costs. Under this scenario the Company does not forecast being in a taxable position for the next two years.

Costs Incurred

During 2005 the Company incurred the following costs in Canada;

	2005
Property Acquisition Costs – Unproved Properties	3,294
Property Acquisition Costs – Proved Properties	(4,273)
Exploration Costs	48,081
Development Costs	38,351
Other	-

Exploration and Development Activities

The following table sets forth the gross and net exploration and development wells in which the Company participated during the year ended December 31, 2005:

	Development Wells		Exploration Wells		Total Wells	
	(gross)	*(net)*	*(gross)*	*(net)*	*(gross)*	*(net)*
Oil wells	4	0.8	-	-	4	0.8
Natural gas wells	19	13.8	18	12.4	37	26.2
Dry and abandoned	-	-	5	2.6	5	2.6
Total	23	14.6	23	15.0	46	29.6

For details on the current and likely exploration and development activities during 2006, see property descriptions on pages R15 and R16.

2006 Production Estimates

The Gundy and West Beg properties accounts for more than 20% of the total production and are identified in the following table. The 2006 production volume estimates in the reserve forecast are the same in both the constant price case and the forecasted price case. The following table indicates the Company working interest average daily production for 2006 by area:

Area	Light and Medium Oil	Associated And Non-Associated Gas	Natural Gas Liquids	Boe
Proved Producing	*(bbls/d)*	*(Mcf/d)*	*(bbls/d)*	*(boe/d)*
Gundy	0	5,262	56	933
West Beg	0	6,633	37	1,142
Other	203	5,788	60	1,228
Total proved producing daily production	203	17,682	152	3,303
Total Proved				
Gundy	0	5,833	62	1,034
West Beg	0	8,036	45	1,384
Other	224	8,143	83	1,664
Total proved daily production	224	22,012	189	4,082
Total Proved Plus Probable				
Gundy	0	6,085	64	1,078
West Beg	0	8,590	48	1,479
Other	230	8,550	87	1,742
Total proved plus probable daily production	230	23,225	199	4,300

	Light and Medium Oil	Natural Gas	Natural Gas Liquids	BOE
	(bbls/d)	*(Mcf/d)*	*(bbls/d)*	*(boe/d)*
Forecasted and Constant Price Cases				
Proved developed producing	203	17,682	152	3,303
Proved developed non-producing	19	2,326	23	429
Proved undeveloped	2	2,004	14	350
Total proved	224	22,012	189	4,082
Probable	6	1,213	10	218
Total proved plus probable	230	23,225	199	4,300

Production History

ProEx's approximate net daily production, before deduction of royalties, for the periods indicated is summarized below.

	2005				2004[1]	
	Q1	Q2	Q3	Q4	Q3	Q4
Light and medium oil (bbls/d)	242	267	272	316	275	252
Natural gas liquids (bbls/d)	89	66	66	88	40	57
Natural gas (mmcf/d)	12.2	12.9	17.3	24.9	3.8	6.4
Total daily production (boe/d)	2,359	2,490	3,214	4,561	949	1,370

(1) ProEx commenced operations on July 2, 2004.

The following table indicates the average daily production for 2005 by area:

Area	Light and Medium Oil	Associated And Non-Associated Gas	Natural Gas Liquids	BOE
	(bbls/d)	*(Mcf/d)*	*(bbls/d)*	*(boe/d)*
Foothills, British Columbia (Gundy area)	34	5,860	27	1,038
Foothills, British Columbia (West Beg area)	11	5,364	14	919
Other	229	5,640	36	1,205
Total Company Daily Production	274	16,864	77	3,162

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the proportion of natural gas or crude oil production. The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and operating netbacks received by ProEx in respect of ProEx's production of crude oil, natural gas liquids and natural gas by quarter for 2005.

	Crude Oil				Natural Gas			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	$/bbl	*$/bbl*	*$/bbl*	*$/bbl*	*$/mcf*	*$/mcf*	*$/mcf*	*$/mcf*
Average Price Received	52.78	59.82	70.94	69.60	7.26	8.05	9.66	11.93
Royalties	(8.43)	(10.92)	(14.85)	(13.96)	(1.88)	(2.24)	(3.03)	(3.88)
Operating Expenses	(5.69)	(6.74)	(7.60)	(8.45)	(0.92)	(1.06)	(0.90)	(0.71)
Netback Received	38.66	42.16	48.49	47.19	4.46	4.75	5.73	7.34

	Q1	Q2	Q3	Q4
Average Selling Price:				
Light and medium crude ($/bbl)	58.47	63.48	74.62	67.99
Natural gas liquids ($/bbl)	52.32	59.38	69.23	69.25
Natural gas ($/mcf)	7.09	7.94	9.54	11.96

The following table indicates the average daily production for 2005:

Area	Light and Medium Oil	Associated And Non-Associated Gas	Natural Gas Liquids	BOE
	(bbls/d)	*(mcf/d)*	*(bbls/d)*	*(boe/d)*
Foothills, British Columbia	47	12,261	49	2,140
Fort St. John Plains, British Columbia	223	4,560	28	1,011
Halkirk, Alberta	4	43	-	11
Total daily production	274	16,864	77	3,162

Additional Reserve Information Presentation

Reserve Life Index

The Company's reserve life index using annualized fourth quarter production is 7.1 years (2004 - 10.2 years) for proved boe reserves and 9.0 years (2004 - 13.7 years) for proved plus probable boe reserves. Reserve life calculated using annualized fourth quarter production may be more reflective of reserve life due to the active capital program and the level of new production added during the fourth quarter.

	2005 Using Annualized Q4 Production	**2005 Using Average Production**	2004 Using Annualized Q4 Production	2004 Using Annualized Average Production
Crude Oil				
Production (mbbls)	**115.3**	**100.0**	92.0	96.4
Proved reserves (mbbls)	**500**	**500**	478	478
Proved reserve life index (years)	**4.3**	**5.0**	5.2	5.0
Proved plus probable reserves (mbbls)	**651**	**651**	655	655
Proved plus probable reserve life index (years)	**5.6**	**6.5**	7.1	6.8
Natural Gas				
Production (mmcf)	**9,103.8**	**6,155.4**	2,323.2	1,863.8
Proved reserves (mmcf)	**64,436**	**64,436**	26,467	26,467
Proved reserve life index (years)	**7.1**	**10.5**	11.4	14.2
Proved plus probable reserves (mmcf)	**82,141**	**82,141**	35,366	35,366
Proved plus probable reserve life index (years)	**9.0**	**13.3**	15.2	19.0
Natural gas liquids				
Production (mbbls)	**32.1**	**28.1**	20.8	17.8
Proved reserves (mbbls)	**532**	**532**	202	202
Proved reserve life index (years)	**16.6**	**18.9**	9.7	11.3
Proved plus probable reserves (mbbls)	**683**	**683**	278	278
Proved plus probable reserve life index (years)	**21.3**	**24.3**	13.4	15.6
Boe				
Production (mboe)	**1,664.8**	**1,154.1**	500.1	423.8
Proved reserves (mboe)	**11,771**	**11,771**	5,091	5,091
Proved reserve life index (years)	**7.1**	**10.2**	10.2	12.0
Proved plus probable reserves (mboe)	**15,024**	**15,024**	6,827	6,827
Proved plus probable reserve life index (years)	**9.0**	**13.0**	13.7	16.1

Notes:

(1) *Gross*

- *(a) In relation to the Company's interest in production or reserves, its "company gross reserves", which are the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interest of the Company.*
- *(b) In relation to wells, the total number of wells in which the Company has an interest.*
- *(c) In relation to properties, the total area of properties in which the Company has an interest.*

(2) *Net*

- *(d) In relation to the Company's interest in production or reserves, the Company's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in production or reserves.*
- *(e) In relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells.*
- *(f) In relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company..*

(3) *Definitions used for reserve categories in the Reserve Report are as follows:*

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- *analysis of drilling, geological, geophysical and engineering data;*
- *the use of established technology; and*
- *specified economic conditions (see Economic Assumptions below)*

Reserves are classified according to the degree of certainty associated with the estimates

- *(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.*
- *(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.*

Economic Assumptions will be the prices and costs used in the estimate, namely:

- *constant prices and costs as at the last day of a reporting issuer's financial year*
- *forecast prices and costs*

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- *(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.*
    - *i. Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.*
    - *ii. Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.*
- *(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.*

  In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- *At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;*
- *At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.*

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

(5) *Forecast prices and costs*

Future prices and costs that are:

(a) Generally accepted as being a reasonable outlook of the future
(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table identifies benchmark reference pricing that apply to the Company.

(6) *Constant prices and costs*

Prices and costs used in an estimate that are:

(a) The Company's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies;
(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Company's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

(10) *The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. ProEx qualifies for the maximum ARTC.*

(11) *Future income tax expenses*

Future income tax expenses estimated (generally, year-by-year):

(a) Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
(b) Without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
(c) Taking into account estimated tax credits and allowances (for example, royalty tax credits); and
(d) Applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

(12) *Development well – A well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.*

(13) *Development costs – Costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:*

(a) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads,, gas lines and power lines, to the extent necessary in developing the reserves;
(b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
(c) Acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
(d) Provide improved recovery systems.

(13) *Exploration well – A well that is not a development well, a service well or a stratigraphic test well.*

(14) *Exploration costs – Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:*

(a) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
(b) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
(c) Dry hole contributions and bottom hole contributions;
(d) Costs of drilling and equipping exploratory wells; and
(e) Costs of drilling exploratory type stratigraphic test wells.

(15) *Service well – A well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.*

(16) *Numbers may not add due to rounding.*

(17) *$M means thousands of dollars.*

(18) *$MM means millions of dollars.*

(19) *The estimates of future net revenue presented in the tables above do not represent fair market value.*

Financials

2005 ProEx Energy Ltd.

MANAGEMENTS REPORT

ProEx Energy Ltd.

The management of ProEx Energy Ltd. is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

ProEx Energy Ltd. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors, composed of non-management Directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy and financial reporting matters. The Committee reviews the annual financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The financial statements have been audited by KPMG LLP, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.

D D Johnson

David D. Johnson
President & CEO

Steven A. Allaire
Vice President, Finance & CFO

Calgary, Canada
February 28, 2006

AUDITORS' REPORT TO THE SHAREHOLDERS

ProEx Energy Ltd.

We have audited the balance sheets of ProEx Energy Ltd., as at December 31, 2005 and 2004 and the statements of earnings and retained earnings, and cash flows for the year ended December 31, 2005 and for the period from July 2, 2004 to December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the year ended December 31, 2005 and for the period from July 2, 2004 to December 31, 2004 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
February 28, 2006

BALANCE SHEETS

ProEx Energy Ltd.

As at December 31 ($ thousands)	**2005**	2004
ASSETS		
Current		
Cash and short-term investments	**667**	2,112
Accounts receivable	**14,248**	7,304
Prepaid expenses and deposits	**368**	67
	15,283	9,483
Property, plant and equipment (Note 3)	**134,910**	61,000
Future income taxes (Note 7)	**-**	2,291
	150,193	72,774
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**24,558**	21,164
Asset retirement obligations (Note 5)	**1,426**	1,936
Future income taxes (Note 7)	**6,259**	-
	32,243	23,100
SHAREHOLDERS' EQUITY		
Share capital and warrants (Note 6)	**100,581**	47,798
Contributed surplus (Note 6)	**637**	159
Retained earnings	**16,732**	1,717
	117,950	49,674
Commitments (Note 10)		
	150,193	72,774

See accompanying notes to the financial statements

Approved on behalf of the Board

Director

D D Johnson

Director

STATEMENTS OF EARNINGS AND RETAINED EARNINGS

ProEx Energy Ltd.

Year ended December 31 ($ thousands, except per share amounts)	**2005**	Period from July 2 to December 31, 2004
REVENUES		
Petroleum and natural gas	**68,086**	9,519
Royalties	**(20,136)**	(2,385)
Interest	**26**	76
	47,976	7,210
EXPENSES		
Operating	**6,164**	1,459
Transportation	**4,008**	489
General and administrative	**1,126**	354
Stock based compensation (Note 6)	**446**	157
Interest and financing	**117**	32
Depreciation, depletion and accretion	**11,417**	1,987
	23,278	4,478
Net earnings before taxes	**24,698**	2,732
TAXES		
Capital taxes	**133**	-
Future income taxes (Note 7)	**9,550**	1,015
	9,683	1,015
NET EARNINGS	**15,015**	1,717
Retained earnings, beginning of period	**1,717**	-
Retained earnings, end of year	**16,732**	1,717
Net earnings per share (Note 6)		
Basic	**$0.49**	$0.06
Diluted	**$0.40**	$0.05

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

ProEx Energy Ltd.

Year ended December 31 ($ thousands)	**2005**	Period from July 2 to December 31, 2004
Cash provided by (used in)		
OPERATING		
Net earnings	**15,015**	1,717
Depletion, depreciation and accretion	**11,417**	1,987
Stock based compensation	**446**	157
Asset retirement expenditures (Note 5)	**(384)**	(121)
Future income taxes	**9,550**	1,015
Funds generated from operations	**36,044**	4,755
Change in non-cash working capital (Note 8)	**(1,261)**	(4,529)
	34,783	226
FINANCING		
Decrease in bank debt	**-**	(10,000)
Issue of shares and warrants (net of share issue costs)	**51,816**	29,930
Change in non-cash working capital (Note 8)	**(30)**	
	51,786	19,930
INVESTING		
Capital expenditures	**(85,454)**	(36,366)
Changes in non-cash working capital (Note 8)	**(2,560)**	18,322
	(88,014)	(18,044)
Increase (decrease) in cash and short-term investments	**(1,445)**	2,112
Cash and short-term investments, beginning of period	**2,112**	-
Cash and short-term investments, end of year	**667**	2,112

See accompanying notes to the financial statements

ProEx Energy Ltd. ("ProEx" or the "Company") was incorporated on April 8, 2004 and commenced commercial operations on July 2, 2004 under a Plan of Arrangement entered into by Progress Energy Ltd. ("Progress"), Cequel Energy Inc., Progress Energy Trust, Cyries Energy Inc. and ProEx. Under the Plan of Arrangement various assets of Progress were transferred to ProEx. At the time of this transaction, Progress and ProEx were related companies resulting in the transfer of assets and related liabilities to ProEx from Progress at their carrying value. As a result, the financial statements presented for the comparative year are for the period from July 2, 2004 to December 31, 2004.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

ProEx is involved in the exploration, development and production of petroleum and natural gas in British Columbia. The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from those estimates.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Company only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

The Company follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

Petroleum and natural gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted

cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, Depreciation and Accretion

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability. No gains or losses on retirement activities were realized due to settlements approximating the estimates.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Income Taxes

The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Stock Based Compensation

The Company follows the fair value method for valuing stock option grants and Class B Performance Share issues. Under this method, compensation cost, attributable to stock options granted and Class B Performance Shares issued to officers and directors of ProEx and employees of Progress in their capacity as service providers, is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options and conversion of Class B Performance Shares, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has not incorporated an estimated forfeiture rate for stock options, and Class B Performance Shares that will not vest, rather, the Company accounts for actual forfeitures as they occur.

2. TRANSFER OF ASSETS AND COMMENCEMENT OF COMMERCIAL OPERATIONS

Under the Plan of Arrangement, Progress transferred to ProEx certain producing and exploratory petroleum and natural gas properties and a proportion of its bank debt. At the time of this transaction, ProEx and Progress were related companies resulting in the transfer of assets and related liabilities to ProEx from Progress at their carrying value as follows:

($ thousands)	Amount
Net assets received:	
Petroleum and natural gas properties	26,377
Future income tax asset	2,898
Bank debt assumed	(10,000)
Asset retirement obligations	(1,813)
Deficit(1)	5,116
Common shares issued (16,229,883 shares)	22,578
Reduction of stated capital(1)	(5,116)
Common shares	17,462

(1) Pursuant to the Plan of Arrangement, the deficit was eliminated by an equal reduction to stated share capital.

Relationship with Progress Energy Ltd.

In conjunction with the Plan of Arrangement, ProEx and Progress entered into a Technical Services Agreement which provides for the shared services required to manage ProEx's activities and define the allocation of general and administrative expenses between the entities. Under the Technical Services Agreement, ProEx is charged a technical services fee by Progress, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. For the year ended December 31, 2005, the technical services fee was $2.8 million ($0.6 million for the period from July 2, 2004 to December 31, 2004). Under the Technical Services Agreement, Progress markets ProEx's natural gas, crude oil and natural gas liquids under standard industry marketing arrangements on a cost recovery basis. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or at some other date as may be mutually agreed. As contemplated in the Plan of Arrangement, the Company has issued Class B Performance Shares and stock options to officers and directors of ProEx and employees of Progress in their capacity as service providers to ProEx.

ProEx and Progress have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition the companies have entered into a Protocol Arrangement that specifies how each company will govern the management of the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. ProEx received an option to farm-in on 25,000 net acres of Progress exploratory lands, retained by Progress, on standard industry terms. Both Progress

and ProEx have created independent committees of their board of directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

As at December 31, 2005, accounts receivable included $1.8 million due from Progress, which includes standard joint venture amounts including revenue. These amounts were received subsequent to the year end.

3. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	**2005**	2004
Petroleum and natural gas properties	**148,126**	62,915
Accumulated depletion, depreciation	**(13,216)**	(1,915)
Property, plant and equipment, net	**134,910**	61,000

During the year ended December 31, 2005, the Company capitalized $0.8 million of general and administrative expenses (2004 - $0.2 million) related to exploration and development activities. The calculation of 2005 depletion and depreciation included an estimated $13.1 million (2004 - $4.9 million) for future development capital associated with proved undeveloped reserves and excluded $22.3 million (2004 – $13.4 million) for the estimated value of unproved properties. Depletion and depreciation expense for the year ended December 31, 2005 was $11.4 million (2004 - $2.0 million).

The Company performed a ceiling test calculation at December 31, 2005 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The prices used in the ceiling test evaluation of the Company's oil and gas assets is summarized in the following chart:

	Crude Oil		Natural Gas
	West Texas Intermediate (Cdn$/bbl)(1)	Edmonton Par Price (Cdn$/bbl)	AECO Gas price (Cdn$/mmbtu)
2006	67.06	66.25	10.60
2007	64.71	64.00	9.25
2008	60.00	59.25	8.00
2009	56.47	55.75	7.50
2010	54.71	54.00	7.20
2011	52.94	52.25	6.90
2012	52.94	52.25	6.90
2013	54.12	53.25	7.05
2014	55.00	54.25	7.20
2015	56.18	55.50	7.40
2016	57.35	56.50	7.55
Thereafter(2)	2.0%	2.0%	2.0%

(1) Future prices incorporated a $0.85 US/Cdn exchange rate.

(2) Percentage change of 2.0% represents the change in future prices each year after 2016 to the end of the reserve life.

4. BANK DEBT

The Company has a $45 million demand revolving operating credit facility with a Canadian chartered bank. The credit facility provides that advances may be made by way of direct advances or bankers' acceptances. Direct advances bear interest at the bank's prime lending rate plus a variable rate and the bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a variable rate per annum stamping fee. The variable rate charged by the bank is dependent upon the Company's debt to trailing cash flow ratio. The credit facility is secured by a $100 million fixed and floating charge debenture on the assets of the Company. The $45 million borrowing base is subject to a semi-annual and annual review by the bank. Subsequent to the year end, the Company increased its demand revolving operating credit facility to $70 million under the same terms as disclosed above.

5. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately $9.4 million which will be incurred over the next 43 years with the majority of costs incurred between 2008 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations. In 2005, the Company increased the inflation rate used to calculate the obligations from 1.5 percent to 2.0 percent. The impact of this change was an increase to the liability of $0.1 million.

The following reconciles the Company's asset retirement obligations:

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Balance, beginning of period	**1,936**	-
Transfer of assets through Plan of Arrangement (Note 2)	**-**	1,813
Liabilities incurred	**762**	159
Liabilities settled	**(384)**	(121)
Acquisitions	**-**	54
Dispositions	**(1,143)**	(41)
Revision to estimated cash flows	**139**	-
Accretion expense	**116**	72
Balance, end of year	**1,426**	1,936

6. SHARE CAPITAL

Authorized

Unlimited number of voting Common Shares, without nominal or par value

701,300 Class B Performance Shares, without nominal or par value

Issued

($ thousands, except share amounts)	2005 Number	2005 Amount	Period from July 2 to December 31, 2004 Number	Period from July 2 to December 31, 2004 Amount
Common Shares				
Issued on incorporation	-	-	1	-
Issued pursuant to private placement	-	-	7,224,175	7,449
Outstanding as at June 30, 2004	-	-	7,224,176	7,449
Balance, beginning of period	**27,450,465**	**45,191**	7,224,176	7,449
Issued pursuant to the plan of arrangement (Note 2)	-	-	16,229,883	17,462
Issued for cash	**5,000,000**	**53,750**	4,000,000	21,000
Issued on exercise of Warrants	**574,018**	**1,005**	-	-
Issued on exercise of Class B Performance shares	**1,962**	-	-	-
Issued on exercise of Options	**2,400**	**18**	-	-
Cancelled	**(31,030)**	**(65)**	(3,594)	(6)
Share issue costs, net of tax $1,000 (2004 - $408)		**(1,706)**		(714)
Balance, end of year	**32,997,815**	**98,193**	27,450,465	45,191
Warrants				
Balance, beginning of period	**7,220,581**	**2,600**	7,224,175	2,601
Exercised	**(574,018)**	**(207)**		-
Cancelled	**(62,060)**	**(12)**	(3,594)	(1)
Balance, end of year	**6,584,503**	**2,381**	7,220,581	2,600
Class B Performance Shares				
Balance, beginning of period	**701,300**	**7**	701,300	7
Exercised	**(2,150)**		-	-
Cancelled	**(4,299)**		-	-
Balance, end of year	**694,851**	**7**	701,300	7
Total share capital and warrants at end of year		**100,581**		47,798

Issue of Common Shares

On June 28, 2004, prior to the completion of the Plan of Arrangement, ProEx completed a private placement of 7,224,175 units to officers, directors and employees of Progress and ProEx, with each unit consisting of one Common Share and one Warrant and 701,300 Class B Performance Shares for gross proceeds of $10.1 million. The ProEx Units were issued at a price of $1.39 per Unit and the Class B Performance Shares were issued at a price of $0.01 per share. One Common Share may be issued for each Warrant at a price of $1.39 per share. The Common Shares are held in escrow and vest over a two year period with one third vesting after six months from the date of issuance, one third vesting after twelve months and one third after twenty four months. The Warrants vest and are

exercisable equally over a three year period starting on the first anniversary date of the issue, June 28, 2005 and expire on June 28, 2008. Each Class B Performance Share is convertible into a fraction of a Common Share equal to the closing trading price of the Common Shares on the Toronto Stock Exchange on the day prior to such conversion less $1.39, if positive, divided by the Common Share closing price. One third of the Performance Shares will be convertible into ProEx Common Shares on each of the first, second and third anniversaries of the closing of the Plan of Arrangement, which is July 2.

On July 2, 2004, pursuant to the Plan of Arrangement 16,229,883 Common Shares were issued to the former shareholders of Progress and Cequel.

On July 22, 2004, the Company issued 4,000,000 Common Shares at a price of $5.25 per share. The proceeds, net of share issue costs of $1.1 million ($0.7 million net of tax), were $19.9 million.

On February 25, 2005, the Company issued 2.5 million Common Shares at a price of $9.10 per share. The proceeds, net of share issue costs of $1.2 million ($0.8 million net of tax) were $21.6 million.

On August 23, 2005, the Company issued 2.5 million Common Shares at a price of $12.40 per share. The proceeds, net of share issue costs of $1.5 million ($0.9 million net of tax) were $29.5 million

Earnings per share

Net earnings per Common Share figures have been calculated using the treasury stock method. The following table reconciles the denominators used for the basic and diluted earnings per Common Share calculations.

Weighted Average Common Shares	2005	Period from July 2 to December 31, 2004
Basic	**30,686,734**	27,040,039
Effect of Warrants	**6,153,613**	5,660,796
Effect of stock options	**47,519**	26,184
Effect of Class B Performance Shares	**634,218**	530,258
Diluted	**37,522,084**	33,257,277

Warrants

One Common Share may be issued for each Warrant at a price of $1.39 per share. The Warrants vest and are exercisable equally over a three year period starting on the first anniversary date of the issue, June 28, 2005 and expire on June 28, 2008.

Stock options

Under the terms of the stock option plan (the "Plan"), directors and officers of ProEx and Progress employees in their capacity as service providers may be granted options to purchase Common Shares. The Plan provides for the granting of up to 10 percent of the issued and outstanding Common Shares of the Company. As at December 31, 2005, the Company could grant up to 3,299,782 options. Options granted under the Plan have a term of five years to expiry and vest equally over a three year period starting on the first anniversary date of the grant. The exercise price of each option equals the market price of the Company's Common Shares on the date of grant.

The following table sets forth a reconciliation of the Plan activity through December 31, 2005.

	Number of options	Weighted average exercise price
Balance, July 2, 2004	-	-
Granted	224,000	5.72
Exercised	-	-
Balance, December 31, 2004	224,000	5.72
Granted	250,000	10.83
Exercised	(2,400)	6.75
Balance, December 31, 2005	471,600	8.38

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2005.

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding at year end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at period end	Weighted average exercise price
$5.60 to $7.95	235,600	3.59	5.85	72,267	5.72
$9.08 to $12.85	208,000	4.32	10.35	-	-
$14.50 to $16.50	28,000	4.85	15.83	-	-
	471,600	3.99	8.38	72,267	5.72

Stock Based Compensation

The Company accounts for its stock based compensation plan using the fair value method. Under this method, a compensation cost is charged over the vesting period for stock options and Class B Performance Shares granted to officers and directors of ProEx and Progress employees in their capacity as service providers, with a corresponding increase to contributed surplus.

The following table reconciles the Company's contributed surplus:

($ thousands)	**2005**	Period from July 2 to December 31, 2004
Balance, beginning of period	**159**	-
Stock based compensation expense		
Stock options	**296**	56
Class B Performance shares	**150**	101
Redemption of Common Shares	**32**	2
Balance, end of year	**637**	159

The fair value of the options granted during the year ended December 31, 2005 and period ended December 31, 2004 was estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

Assumptions	**2005**	Period from July 2 to December 31, 2004
Risk free interest rate (%)	**3.25**	3.08
Expected life (years)	**3.00**	2.24
Expected volatility (%)	**40**	59
Weighted average fair value of options granted ($)	**3.54**	1.75

7. FUTURE INCOME TAXES

The provision for future income taxes in the statements of earnings and retained earnings reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

($ thousands)	2005	Period from July 2 to December 31, 2004
Net earnings before taxes	**24,698**	2,732
Statutory income tax rate	**38.24%**	39.40%
Expected income taxes	**9,445**	1,076
Add (deduct):		
Non-deductible crown charges	**4,154**	536
Resource allowance	**(3,329)**	(486)
Other	**(720)**	(111)
Future income tax expense	**9,550**	1,015

The future income tax liability at December 31, 2005 and future income tax asset at December 31, 2004 is comprised of the tax effect of temporary differences as follows:

($ thousands)	2005	2004
Property, plant and equipment	**7,905**	(721)
Asset retirement obligations	**(483)**	(667)
Loss carry-forward	**-**	(509)
Share issue costs	**(997)**	(348)
Attributed Canadian Royalty Income	**(166)**	(46)
Future income tax liability (asset)	**6,259**	(2,291)

As at December 31, 2005, the Company has tax deductions of approximately $118.0 million (2004 - $65.3 million) that is available to shelter future taxable income.

8. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

($ thousands)	2005	Period from July 2 to December 31, 2004
Accounts receivable	**(6,944)**	(7,304)
Prepaid expenses and deposits	**(301)**	(67)
Accounts payables and accrued liabilities	**3,394**	21,164
Change in non-cash working capital	**(3,851)**	13,793
Relating to:		
Financing activities	**(30)**	-
Investing activities	**(2,560)**	18,322
Operating activities	**(1,261)**	(4,529)

Interest

($ thousands)	2005	Period from July 2 to December 31, 2004
Interest paid	**92**	6
Interest received	**26**	76

9. FINANCIAL INSTRUMENTS

Fair value of financial assets

The Company's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, accounts payable and accrued liabilities. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity.

Credit risk

Substantially all of the Company's petroleum and natural gas production is marketed under standard industry terms by Progress in accordance with the Technical Services Agreement. ProEx monitors the financial condition of Progress on a quarterly basis in order to mitigate the concentration of credit risk with this counterparty. All other accounts receivable are with customers and joint venture partners in the petroleum and natural gas business under normal industry sale and payment terms and are subject to normal credit risks. The Company routinely assesses the financial strength of its customers.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's debts that have a floating interest rate. The Company had no interest rate swaps or hedges at December 31, 2005.

10. COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment and future minimum payments for drilling rig contracts. Payments required under these commitments for each of the next five years are: 2006 - $13.2 million; 2007 - $9.4 million; 2008 - $8.7 million; 2009 - $7.4 million; 2010 - $7.0 million; and thereafter $4.2 million.

2005 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

FINANCIAL HIGHLIGHTS

($ thousands, except per share amounts)	Three months ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Income Statement					
Petroleum and natural gas revenues	9,452	11,217	17,434	29,983	68,086
Funds generated from operations	5,001	5,589	8,953	16,501	36,044
Per share – basic	0.18	0.19	0.29	0.50	1.17
Per share – diluted	0.14	0.15	0.23	0.41	0.96
Net earnings	1,737	1,919	3,585	7,774	15,015
Per share – basic	0.06	0.06	0.11	0.24	0.49
Per share – diluted	0.05	0.05	0.09	0.20	0.40
Balance Sheet					
Capital investment					
Land acquisitions and retention	1,017	782	967	4,916	7,682
Geological and geophysical	5,723	2,171	540	3,347	11,781
Drilling and completions	16,060	5,242	17,007	17,563	55,872
Equipping and facilities	7,075	2,906	5,911	2,887	18,779
Net property acquisitions (dispositions)	(12,090)	10	3,403	17	(8,660)
	17,785	11,111	27,828	28,730	85,454
Total debt					
Bank debt	-	5,000	-	-	-
Working capital deficiency (surplus)	2,905	3,455	(2,915)	9,275	9,234
	2,905	8,455	(2,915)	9,275	9,234
Shareholders' equity	73,500	75,505	110,008	117,950	117,950
Share Information *(thousands, except per share amounts)*					
Shares outstanding at end of period					
– Common	29,950	29,950	32,974	32,998	32,998
Weighted average shares outstanding for the period					
– Basic	28,423	29,950	31,330	32,986	30,687
– Diluted	35,242	36,800	38,251	39,832	37,522
Volume traded	5,273	4,408	11,867	6,588	28,136
Common share price ($)					
– High	11.80	11.60	17.97	18.50	18.50
– Low	7.61	9.03	10.85	14.52	7.61
– Closing	10.10	10.65	17.97	16.40	16.40

2005 Selected Quarterly Information

ProEx Energy Ltd.

OPERATIONAL HIGHLIGHTS

($ thousands, except per share amounts)	Three months ended 2005				Annual
	March 31	June 30	Sept. 30	Dec. 31	2005
Production					
Natural gas (mcf/d)	12,170	12,943	17,255	24,942	16,864
Crude Oil (bbls/d)	242	267	272	316	274
Natural gas liquids (bbls/d)	89	66	66	88	77
Total production (boe/d)	2,359	2,490	3,214	4,561	3,162
Pricing					
Natural gas ($/mcf)	7.09	7.91	9.54	11.96	9.70
Crude oil ($/bbl)	58.47	63.48	74.62	67.99	66.49
Natural gas liquids ($/bbl)	52.32	59.38	69.23	69.25	62.32
Highlights					
Petroleum and natural gas revenues	44.52	49.51	58.96	71.46	58.99
Royalties	(11.00)	(13.02)	(17.89)	(22.79)	(17.45)
Interest income	0.04	0.03	0.01	0.02	0.02
Operating expenses	(5.56)	(6.42)	(5.58)	(4.48)	(5.34)
Transportation expenses	(3.22)	(3.59)	(3.71)	(3.37)	(3.47)
Operating netback	24.78	26.51	31.79	40.84	32.75
General and administrative expenses	(0.35)	(1.33)	(0.84)	(1.20)	(0.98)
Interest expenses	-	(0.16)	(0.08)	(0.13)	(0.10)
Asset retirement expenditures	(0.83)	(0.27)	(0.44)	(0.04)	(0.33)
Capital taxes	(0.04)	(0.08)	(0.15)	(0.06)	(0.11)
Funds generated from operations	23.56	24.67	30.28	39.41	31.23
Asset retirement expenditures	0.83	0.27	0.44	0.04	0.33
Stock based compensation expense	(0.46)	(0.46)	(0.39)	(0.30)	(0.39)
Depletion, depreciation and accretion expenses	(9.74)	(10.78)	(9.63)	(9.68)	(9.89)
Net earnings before taxes	14.19	13.70	20.70	29.47	21.28
Future income taxes	(6.01)	(5.23)	(8.58)	(12.30)	(8.27)
Net earnings	8.18	8.47	12.12	17.17	13.01
Gross Drilling Results					
Natural gas	12	2	9	14	37
Crude oil	1	-	2	1	4
Dry and abandoned	3	-	-	1	4
	16	2	11	16	45
Net Drilling Results					
Natural gas	7.4	1.0	8.2	9.6	26.2
Crude oil	0.2	-	0.4	0.2	0.8
Dry and abandoned	1.4	-	-	0.2	1.6
	9.0	1.0	8.6	10.0	28.6
Success rate *(%)*	84	100	100	98	94

2004 SELECTED QUARTERLY INFORMATION

ProEx Energy Ltd.

FINANCIAL HIGHLIGHTS

($ thousands, except per share amounts)	Three months ended 2(		Annual
	Sept. 30[1]	Dec. 31	2004[2]
Income Statement			
Petroleum and natural gas revenues	3,695	5,824	9,519
Funds generated by operations	1,882	2,873	4,755
Per share – basic	0.07	0.11	0.18
Per share – diluted	0.06	0.09	0.14
Net earnings	663	1,054	1,717
Per share – basic	0.02	0.04	0.06
Per share – diluted	0.02	0.03	0.05
Balance Sheet			
Capital investment			
Land acquisitions and retention	3,099	2,040	5,139
Geological and geophysical	351	500	851
Drilling and completions	3,631	15,574	19,205
Equipping and facilities	1,625	5,030	6,655
Net property acquisitions (dispositions)	66	4,440	4,506
Corporate assets	-	10	10
	8,772	27,594	36,366
Total debt			
Bank debt	-	-	-
Working capital deficiency (surplus)	(13,046)	11,681	11,681
	(13,046)	11,681	11,681
Shareholders' equity	48,543	49,674	49,674
Share Information *(thousands, except per share amounts)*			
Shares outstanding at end of period			
– Common	27,454	27,450	27,450
Weighted average shares outstanding for the period			
– Basic	26,541	27,452	27,040
– Diluted	32,595	33,874	33,257
Volume traded	9,770	6,039	15,809
Common share price ($)			
– High	6.80	8.25	8.25
– Low	5.12	6.30	5.12
– Closing	6.70	8.20	8.20

(1) Period from July 2, 2004 to September 31, 2004
(2) Period from July 2, 2004 to December 31, 2004

2004 Selected Quarterly Information

ProEx Energy Ltd.

OPERATIONAL HIGHLIGHTS

($ thousands, except per share amounts)	Three months ended 2004		Annual
	Sept. 30(1)	Dec. 31	2004(2)
Production			
Natural gas (mcf/d)	3,806	6,365	5,092
Crude Oil (bbls/d)	275	252	263
Natural gas liquids (bbls/d)	40	57	49
Total (boe/d)	949	1,370	1,161
Pricing			
Natural gas ($/mcf)	6.38	7.32	6.97
Crude oil ($/bbl)	52.83	56.28	54.49
Natural gas liquids ($/bbl)	44.44	44.69	44.59
Highlights			
Petroleum and natural gas revenues	42.78	46.21	44.81
Royalties	(9.96)	(12.10)	(11.23)
Interest income	0.35	0.36	0.36
Operating expenses	(7.64)	(6.33)	(6.87)
Transportation expenses	(2.05)	(2.48)	(2.30)
Operating netback	23.48	25.66	24.77
General and administrative expenses	(1.33)	(1.90)	(1.67)
Interest expenses	(0.07)	(0.20)	(0.15)
Asset retirement expenditures	(0.29)	(0.76)	(0.57)
Capital taxes	-	-	-
Funds generated from operations	21.79	22.80	22.38
Asset retirement expenditures	0.29	0.76	0.57
Stock based compensation expense	(0.87)	(0.64)	(0.74)
Depletion, depreciation and accretion	(8.16)	(10.18)	(9.36)
Net earnings before taxes	13.05	12.74	12.85
Future income taxes	(5.37)	(4.37)	(4.77)
Net earnings	7.68	8.37	8.08
Gross Drilling Results			
Natural gas	4	14	18
Crude oil	-	1	1
Dry and abandoned	-	-	-
	4	15	19
Net Drilling Results	100	100	100
Natural gas	3.2	10.2	13.4
Crude oil	-	0.2	0.2
Dry and abandoned	-	-	-
	3.2	10.4	13.6
Success rate *(%)*	100	100	100

(1) Period from July 2, 2004 to September 31, 2004
(2) Period from July 2, 2004 to December 31, 2004

SHAREHOLDER INFORMATION

Annual Meeting

The Annual General Meeting of Shareholders will be held on Tuesday, April 25, 2006 at 3:30 p.m. in the McMurray Room, Calgary Petroleum Club, Calgary, Alberta.

Annual Information Form

Copies of the Annual Information Form are available to shareholders upon request.

www.progressenergy.com

Shareholders and interested investors are encouraged to visit our web site. Historical public disclosure documents (in PDF format), latest presentation material, press releases are all available. Filings also available at:www.sedar.com

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Investor Relations

Steven A. Allaire
Vice President Finance & CFO
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Corporate Governance

A system of corporate governance for the Corporation has been established to provide the Board of Directors, management and shareholders of the Corporation with effective governance. A more detailed discussion of corporate governance Is available in the Information Circular for the Annual General Meeting of Shareholders.

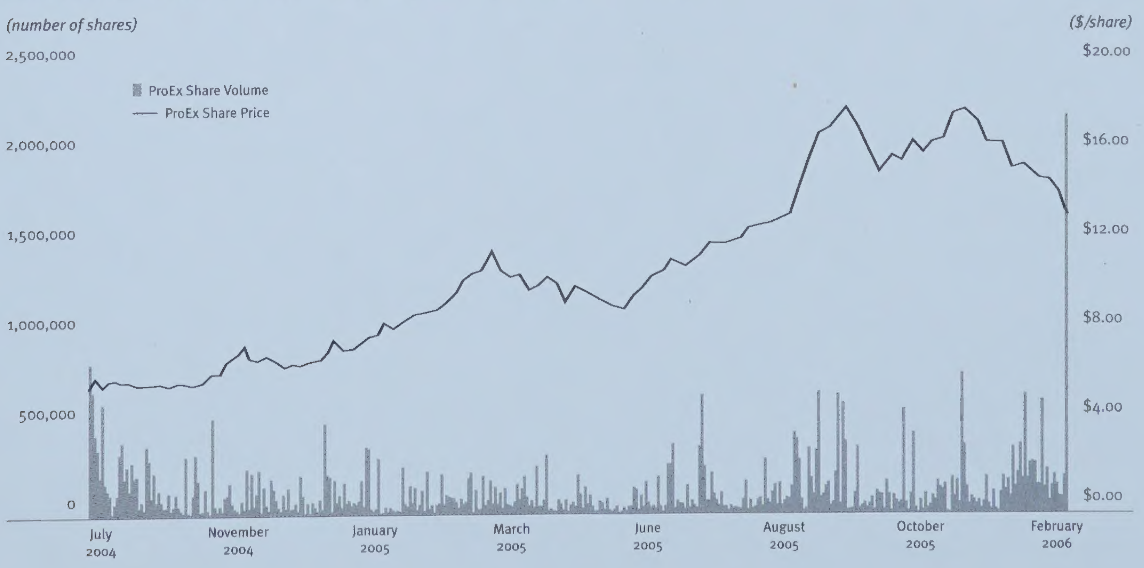
Stock Exchange Listings

The Toronto Stock Exchange
Symbol: PXE

Estimated Release Date of Quarterly Results

First Quarter April 24, 2006
Second Quarter July 25, 2006
Third Quarter October 24, 2006

SHARE VOLUME AND SHARE PRICE (July 7, 2004 to February 22, 2006)



CORPORATE INFORMATION

Directors

John M. Stewart [1][4]
Chairman
ProEx Energy Ltd.
Vice Chairman
ARC Financial Corporation
Calgary, Alberta

David D. Johnson
President &
Chief Executive Officer
ProEx Energy Ltd.
Calgary, Alberta

Brian Mclachlan [2][3][4]
President &
Chief Executive Officer
Yoho Resources Inc.
Calgary, Alberta

Gary E. Perron [1][2]
Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

Terrance D. Svarich [1][3][4]
President
Devsun Ltd.
Calgary, Alberta

Officers

David D. Johnson
President &
Chief Executive Officer

Steven A. Allaire
Vice President Finance &
Chief Financial Officer &
Corporate Secretary

Corporate Office

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Bankers

Bank of Montreal
Corporate Banking
1400, 421 – 7th Avenue SW
Calgary, Alberta T2P 2P2

Solicitor

Burnet, Duckworth & Palmer
1400, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9

Auditor

KPMG LLP
1200, 205 – 5th Avenue SW
Calgary, Alberta T2P 4B9

Consulting Engineer

GLJ Petroleum Consultants
4100, 400 – 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

(1) *Member of Audit Committee*
(2) *Member of Compensation Committee*
(3) *Member of Reserve Committee*
(4) *Member of Technical Services Committee*

Environment, Health and Safety, Corporate Governance and Nomination Matters are addressed by the entire Board of Directors

ProEx Energy Ltd.
2005 Annual Report

ProExEnergy

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